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ELECTRIC POWER WHEELING AND DEALING:

Technological Considerations for Increasing Competition

VOLUME II -- CONTRACTOR DOCUMENTS

Part B

1. Case Studies on Increasing Transmission Access
2. Case Studies of Transmission Bottlenecks
3. Technological Considerations in Proposed Scenarios for Increasing Competition in the Electric Utility Industry
4. Technical Background and Considerations in Proposed Increased Wheeling, Transmission Access an Non-Utility Generation

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J952-59

CASE STUDIES ON INCREASING TRANSMISSION ACCESS

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TABLE OF CONTENTS

I. EXECUTIVE SUMMARY 1

II. NATURE OF TRANSMISSION CONSTRAINTS 1
  A. Importance of Transmission Constraints 1
    1. Economic Dispatch 1
    2. Control Areas and Functions 3
    3. Planning and Operating Constraints 5
    4. Overall National Picture 8
  B. Technical Limitations to Transfers 8
    1. Individual Line Constraints 8
    2. System Constraints 11
    3. Interrelationship of Constraints 12
    4. Preventive and Corrective Modes 14
    5. Need for Reserves for Emergencies 14
  C. Temporal and Economic Factors Affecting Constraints . . . 15

III. BASIS AND APPROACH FOR CASE STUDIES 1
  A. The Five Scenarios 1
  B. Factors Investigated and Basis for Selecting Case Studies . . . 7
  C. The SCE System and Transmission Constraints 14
  D. Description of the PJM System and Transmission Constraints . . . 16

IV. SOUTHERN CALIFORNIA EDISON CASE STUDY 1
  A. Means of Increasing Transmission Capability 1
  B. Problems with Transmission Access and Wheeling 2
  C. Implementation of Deregulation Scenarios 5

V. PJM INTERCONNECTION CASE STUDY 1
  A. Means of Increasing Transmission Capacity 1
  B. Problems with Transmission Access and Wheeling 7
  C. Implementation of Deregulation Scenarios 8

APPENDICES

A. Summaries of Transmission Conditions Around Country
B. Expanding Transmission Capability: Corrective Technology Applications
C. Expanding Transmission Capability: HVDC Terminal Expansion Project
D. Expanding Transmission Capability: Use of Phase Shifters
E. Expanding Transmission Capability: Alternatives to Devers-Palo Verde 500-kV Line
F. Expanding Transmission Capability: Rapid Adjustment of Network Impedance

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I. EXECUTIVE SUMMARY

The ability of the Southern California Edison Company and the Pennsylvania-New Jersey-Maryland Interconnection (PJM) to meet the requirements of various proposed deregulation scenarios has been examined. (PJM is a contractual relationship among eight utilities in the middle Atlantic area.) The technical implications of five alternative scenarios, each representing a different degree of change in the regulatory process of the electric power industry are reviewed. The scenarios are a distillation of a variety of proposals for increasing competition in the industry.

The five alternative scenarios range from what are essentially the existing utility circumstances with some modifications; through scenarios of expanded access to transmission and mandatory wheeling; to full competition for bulk power supplies and disaggregation of utility functions, which consists of separating the present vertically-integrated utilities into separate entities performing, respectively, generation, transmission, and distribution functions. The scenarios are shown in detail in Table III-1.

A particular focus of the investigation was the degree to which the transmission system would limit, or be affected by, the various scenarios.

The report includes both general material, in particular a discussion of the temporal and economic factors that make transmission constraints vary with time, and material specific to the individual cases. The case-specific material includes a review of what can be done to increase transmission capability in the area involved, and an examination of what changes in planning and operating procedures and utility facilities would be needed in order to implement each of the five scenarios.

The analyses of both the SCE system and the PJM system have been conducted based on two fundamental ground rules:

1. The advantages of increased competition should not result in a decline in the reliability of the systems.
2. The present economic benefits from intercompany coordination, which

produces the greatest overall generation savings compatible with reliability, should not be given up in any of the scenarios.

These ground rules were chosen in order to show the consequences of the proposed deregulation scenarios, and to keep them separate from the consequences of other decisions which are not necessarily related to deregulation. For example, service reliability could be reduced as a deliberate decision, in order to reduce the cost of service. If the ground rules were violated by accepting a reduction in reliability with one scenario but not with another, it would be impossible to compare these two scenarios on their merits in other respects, such as their effect on planning and operating procedures and on the physical system requirements.

When either reliability or intercompany coordination benefits were deemed to be affected by a scenario, thorough discussions and investigations were made of technical and procedural changes which might overcome the loss of these important economic benefits.

For both systems investigated, the utility participants stated that in discussing the different scenarios they were assuming that necessary legislative changes would be made so that the utilities would not be subject to retroactive prudency tests by future regulators after they implemented the scenarios.

Consistent conclusions were reached for the two systems which were investigated, in spite of their very different locations, organizations, and technical situations. Both systems now have transmission limitations which adversely affect the degree to which optimum energy transfers can be accommodated by their power supply systems. They have used a great variety of old and new technologies to increase their ability to transfer power for maximum economy.

Although there were some differences in the expectations and concerns of the two systems about the various deregulation scenarios, the following major conclusions were reached in both cases by the investigators, with substantial agreement of the utilities studied:

1. If the present level of reliability and present economics due to inter-utility coordination are to be maintained, all units not owned by utilities must be designed, maintained, and operated in the same way that a similar utility-owned unit would be. This requires that non-utility generators (NUGs) should be subject to:

   - direct operating control by providing for the right of the utility (and the contractual and physical tools to implement such right) to connect, disconnect, and control power output and voltage of all connected units, regardless of ownership, to protect the reliability of the transmission system;
   - central economic dispatch based on unit incremental energy production costs;
   - tie line and frequency control requirements;
   - maintenance scheduling determined by the utility;
   - operation so as to provide spinning and regulating capacity;
   - providing system reactive power requirements; and
   - providing generation and connecting transmission designed, operated, and maintained to utility standards.

   Failure to apply these rules in existing systems in which the non-utility units only amount to a small fraction of the total system capacity may not have serious consequences.

   These concerns become particularly important, however, as non-utility generation becomes a more significant portion of the total generation supply or larger NUG units are installed.

   Theoretically, most of these requirements could be satisfied by including appropriate provisions in all contracts between non-utility generators and the utility, transmission company, and/or distribution company, as applicable for each scenario. However, there are grounds for concern that present or future laws or regulations might not permit the utilities to require the needed provisions in the contracts, or that the contracts might not be effectively enforceable if it becomes advantageous to a non-utility power supplier to default on the contractual obligation. Even damages, if collected, do not replace required power supplies when power is needed. This leads to a general conclusion that, even if the utilities or their successors were to obtain the proposed contractual terms in power supply contracts, the ultimate effect would be a reduction in the reliability and overall economy of the electric power supply.

2. Scenarios that involve mandatory wheeling without adequate notice, or that permit customers to shop for suppliers, will require substantial additional transmission facilities. Present transmission systems are designed to carry reasonably predictable amounts from predictable sources to predictable loads. When these quantities and terminals become less predictable, a much more extensive transmission system is needed to open additional markets to many different potential suppliers. Much of this additional transmission will not be used the majority of the time since, of the many potential sources for which transmission must be provided so that they can enter competitive bidding, only some will bid successfully to become regular suppliers over the transmission system.

3. Competition among utilities to sell to customer loads and to buy from economic suppliers will severely restrict inter-utility exchange of information, and will make it difficult or impossible to develop generation plans coordinated on a regional basis, and to plan and design a well-integrated regional transmission system for maximum reliability and economy.

   Competition between utilities for power sources may also impair the coordination of operations for reliability and economy.

   Also, scenarios in which the customers are permitted to shop for suppliers will require larger generation reserves to be available to supply possible future loads, as uncertainty grows concerning the plans of customers and non-utility generators. This will tend to increase generation requirements to maintain service reliability, since utilities, which currently have an obligation to serve, must protect against failure of non-utility generators to fulfill their capacity commitments, and must provide for unexpected loads, by increasing their reserve goals.

4. The changes in utility planning and operating procedures which are needed to maintain existing reliability and coordination benefits would be substantial, especially for the more radical deregulation scenarios, and their costs could exceed any "economic efficiency" benefits. Control of the system for reliability and economy becomes much more complex as the number of parties involved multiplies due to the entry of many small producers into the system. The number of control centers would have to be increased, as well as their complexity and cost. Even with considerable expansion in the number of control centers, personnel assigned, computers and software and special training, the ability to maintain reliability remains questionable.

5. The various deregulation scenarios will tend to result in increased dependence on natural gas and oil as fuel, and hence reduce the security of electric supply during times of scarcity of these fuels.

6. Transactions that do not result in a change in the generation pattern cannot affect the overall economic efficiency of the operating system; they only represent a reallocation of costs and benefits. This is not to say that there may not be some other long range effects from these transactions, including some socio-economic changes and changes in incentives.

Table I-1 summarizes the most important conclusions obtained in the case studies.

A deliberate reduction in the accepted service reliability standard would reduce the need for some of the changes which would be needed to maintain the existing level of reliability. While no quantitative evaluation was made of this relationship, it is the investigators' judgement that only a very serious reduction in service reliability would significantly change the conclusions of this report as to the changes needed to implement the deregulation scenarios. Such a reduction would have far-reaching consequences, affecting both the industrial efficiency and the general standard of living of the nation.

TABLE I-1: SUMMARY OF CHANGES REQUIRED TO IMPLEMENT VARIOUS DEREGULATION SCENARIOS

* Note: Changes for each scenario include those shown for lower-numbered scenarios except where indicated.

SCENARIO	LEGAL AND REGULATORY CHANGES	PROCEDURAL CHANGES - OPERATION	PROCEDURAL CHANGES - PLANNING	TECHNICAL CHANGES
1. Status Quo, plus Rolling Prudency Review	- Legal changes to bind later commissions to present commission's approval of decisions.	- Control by utility of NUG units scheduling, startup, shutdown, output, voltage control, etc. NUG to provide control and communication equipment to implement utility control. (Degree of necessity depends on proportion of NUG generation to total.)	- Periodic review by PUC of utility and non-utility plans, requirements, and status of projects.	- Depending on amount of NUG generation: additional transmission, remedial measures, increased generation reserves, control and communications systems. - Utility to specify NUG design standards which affect reliability.
2. Expanding Transmission Access in the Existing Institutional Structure	- Allow utility flexibility in rates to compete for supplier-shopping customers.		- NUG to provide 3-5 years advance notice for capacity credit or firm transmission. Same for firm transmission to supplier-shopping customers. - Special PJM procedures to prevent omissions and double-counting in resources planning. - Cooperation in planning will suffer, require additional plant.	- Same as Scenario 1, but more.
3. All-Source Competitive Bidding for New Generation with Mandatory Wheeling	- Utility to determine amount, type, and timing of additions. - Utility to select best bid. - Time limit on appeals to commission. - Provision of transmission to NUG should be voluntary, and use flexible pricing basis.		- NUG to provide sufficient advanced notice and financial commitment for firm wheeling.	- Same as 2.
4. Generation Segregated from Transmission and Distribution Services	- Establish responsibility and authority of transmission company.	- Need for a Transmission Pool combining the Transmission companies. - Transmission Company, or Transmission Pool, must operate the transmission system and protect reliability. - Transmission Pool should provide economic dispatch.	- Each member to provide generation capacity. - Transmission Pool to make all energy purchases. - Distribution (or Transmission/ distribution) company needs to arrange for generation supply with adequate lead time. - Backup contracts needed to back up the transmission pool's energy purchases. - Same as Scenario 3.	

TABLE I-1 (Continued)
Page Two

SCENARIO	LEGAL AND REGULATORY CHANGES	PROCEDURAL CHANGES - OPERATION	PROCEDURAL CHANGES - PLANNING	TECHNICAL CHANGES
5. Common Carrier Services in a Disaggregated, Market-Oriented Electric Power Industry	- Definition of "common carrier" responsibilities of transmission companies as needed.	- PJM transmission companies may need to be horizontally integrated. (PJM) - Coordination procedures between generation, transmission, and distribution companies must be carefully defined in contracts.	- Transmission Company must study, and build transmission for, all reasonable combinations of sources and consumption points. - Much greater uncertainty about sources and loads leads to higher reserve requirements for generation and transmission. - Requiring 8-10 years notice for guaranteed firm service would be much more economical than guaranteeing instant service.	- Very major expansions of transmission system. - Additional generation reserves needed for reliability equal to present.

II. NATURE OF TRANSMISSION CONSTRAINTS

Transmission constraints can have a serious impact on the reliability and economy of power system operation. This section discusses the nature and effect of transmission constraints.

A. Importance of Transmission Constraints

The effect of transmission constraints is to reduce reliability or increase reserve requirements as compared to the situation with no transmission constraints. They may also interfere with economic power system operations and, in particular, with the practice of economic dispatch. Some examples of the impacts of transmission constraints are:

1. On reliability: In determining generating capacity reserve requirements, the planned capacity and projected loads of adjoining power systems are generally recognized. If a transmission constraint prevents the full amount of capacity needs from being imported or available generating capacity from being exported, the reserves must be larger to maintain the same level of reliability.

2. On economic dispatch: economic dispatch based on incremental production costs is the universally recognized principle for loading the generators of an electric system. This method produces the lowest total cost of energy production. Transmission constraints can result in uneconomic dispatch to alleviate line loadings.

1. *Economic Dispatch*

Today's electric power systems are being dispatched and operated based on the incremental costs of production. This general practice often results in one utility producing electricity for use by another utility's customers since the first utility can produce the power at a lower cost. This leads to maximum, economic efficiency in the use of the investment and in the cost of operating these systems. No other industry in the United States operates in this way, whereby alternate suppliers all work together to produce a common product, using plants which have the lowest incremental cost to produce the additional units needed regardless of plant ownership.

The only exception to this production based on incremental costs has resulted from the recent addition of cogenerators and qualifying facilities. The proposed addition of independent power producers could increase further the amount of generation that is not economically operated based on incremental production costs.

The incremental production cost of a generating unit is the additional cost per kilowatt-hour of generating a small additional quantity of energy from that unit or the cost reduction per kwh due to generating a lesser quantity of energy. Generally, this incremental cost consists mostly of additional fuel costs, but it also includes any other operation costs that vary with the level of power production. The incremental cost of a generator is affected mostly by the cost of its fuel and by how efficiently it converts this fuel into electric power. For a typical thermal unit, the incremental cost increases as production increases from the minimum to the maximum rated output. The incremental cost of a unit is not the same as its average cost, which generally decreases as its output increases. Figures II-1a and II-1b illustrate this point for a typical generating unit. Figure II-1a is a simplified "input-output" curve, which shows the total cost of operating the unit, in dollars per hour, as a function of the output in megawatts. Figure II-1b shows the average cost (solid line) and incremental cost (dotted line) for that unit. The average production cost at any output level is obtained by dividing the cost by the output; this value generally decreases as output increases. The incremental production cost, however, is represented by the slope of the input-output curve, because it indicates the additional cost of increasing output by one megawatt. This quantity generally increases as unit output increases.

Economic dispatch consists of supplying the system's total power requirements at any time by loading each available unit to the point where its incremental cost is the same as that of all the others. Units whose highest incremental cost is lower than the common incremental cost are, of course, loaded to their maximum capability.

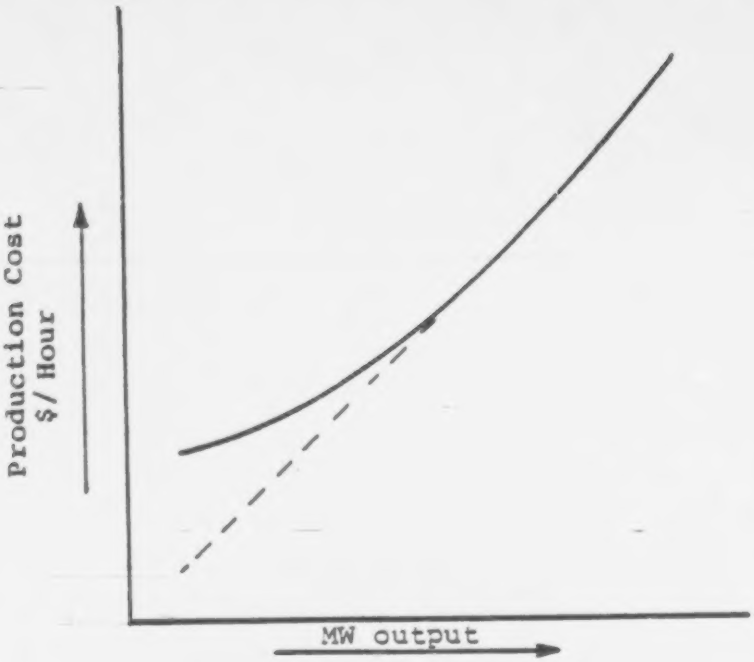
In performing economic dispatch to minimize total power production costs, the limitations on the transmission system's capability to transfer power reliably must be observed. If economic dispatch causes too much power to be transferred from one area to another, it is necessary to reduce the output of units in the sending area, and increase the output of units in the receiving area. This deviation from economic dispatch in order to observe transmission constraints causes a cost increase due to those transmission constraints.

The principle of economic dispatch is almost universally observed within individual utilities, which frequently implement it with automatic computer control of generator outputs. The same principle is also very widely applied in inter-utility transactions. If one utility is operating at a higher system incremental cost than another, the former will buy energy from the latter until the incremental costs are matched or until transmission constraints are reached. This type of transaction is sometimes very highly automated, as in the case of the PJM Interconnection. In other cases, the process is less automated and is carried out through brokerage systems or through individual transactions negotiated by system operators using telephones or small computer networks.

It is important to note that inter-utility transactions are implemented simply by increasing the generation of the selling utility and decreasing that of the buying utility. When two systems are connected to each other by more than one transmission link, whether directly or indirectly through other utilities, it is not possible to direct a power interchange along a specific link. The power flows between the systems in accordance with the physical laws that govern the flow of electricity. The importance of this fact, and the existence of one exception, will be seen in the discussion of the nature and causes of transmission constraints.

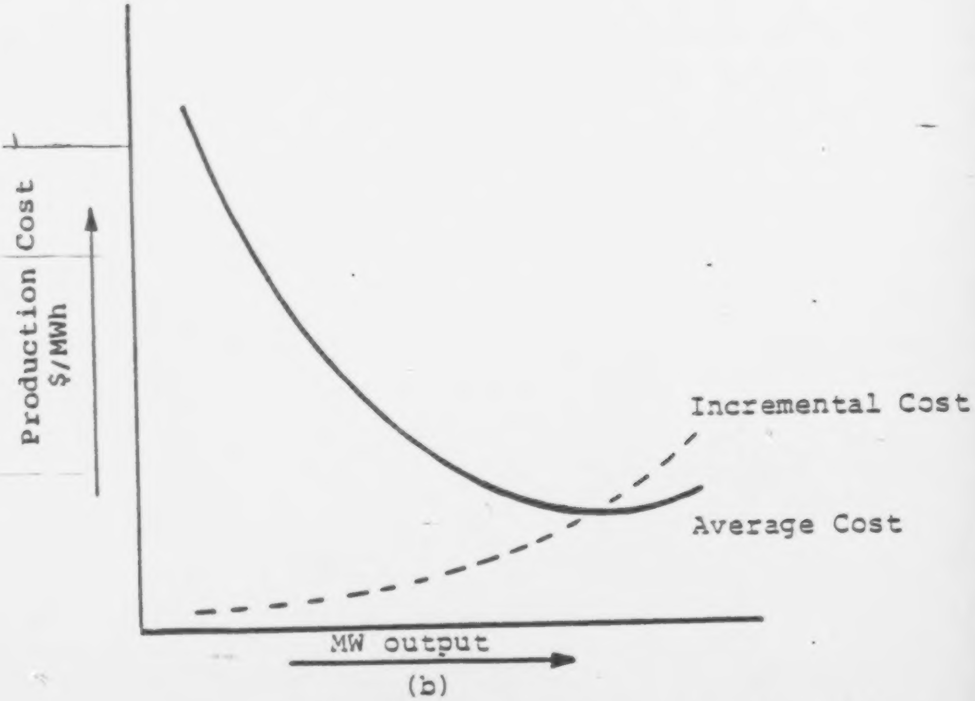
2. *Control Areas and Functions*

In the United States, all electric utilities are connected to neighboring utilities through one or more links. Except where contrary arrangements are specifically made, it is the responsibility of each utility to provide the power used by its customers without absorbing power from its neighbors or sending unwanted power to them. This general principle is implemented through the institution of control areas.



(a)

Total Production Cost Curve



(b)

Incremental and Average Production Cost Curve

FIGURE II-1

A control area is a utility or group of utilities with the following characteristics:

- The power flow across every transmission link between the control area and neighboring control areas is monitored by the control area operating center.
- Automatic controls adjust the output of generators inside the control area in such a way that the total power transferred across the borders of the control area is equal to the net sales or purchases transacted between the utilities inside and outside the control area.

Every utility in the United States is, or is part of, a control area. The operation of control areas ensures that the utilities within the control area, taken as a group, will fulfill their responsibility of providing for their own loads and carry out scheduled transactions. While, as mentioned earlier, they cannot ensure specific flows along specific transmission lines, they do provide a form of control in the sense that the flows over given transmission lines can be predicted for a given transaction schedule, using the control computers of the various control areas. A map of the principal control areas of the United States is shown in Figure II-2.

Control areas also cooperate with each other to maintain the power supply frequency at 60 Hertz by adjusting their generation whenever the frequency begins to deviate from the standard. Transmission capacity must be reserved for this function since significant frequency deviations are generally caused by the loss of a major power source, such as a complete power plant, and this will cause major power in-rushes throughout an extensive geographic area.

3. *Planning and Operating Constraints*

Transmission constraints affect both the operation and the planning of power systems, but do so in different ways. Most utilities have developed system planning criteria which set the conditions that must exist on the system if various contingencies occur. For example, the planning criteria might specify that normal economic dispatch should be possible without exceeding transmission limitations both when the transmission system is in a normal state (all facilities in service), and also under certain contingencies, such as the loss of specific individual facilities because of maintenance

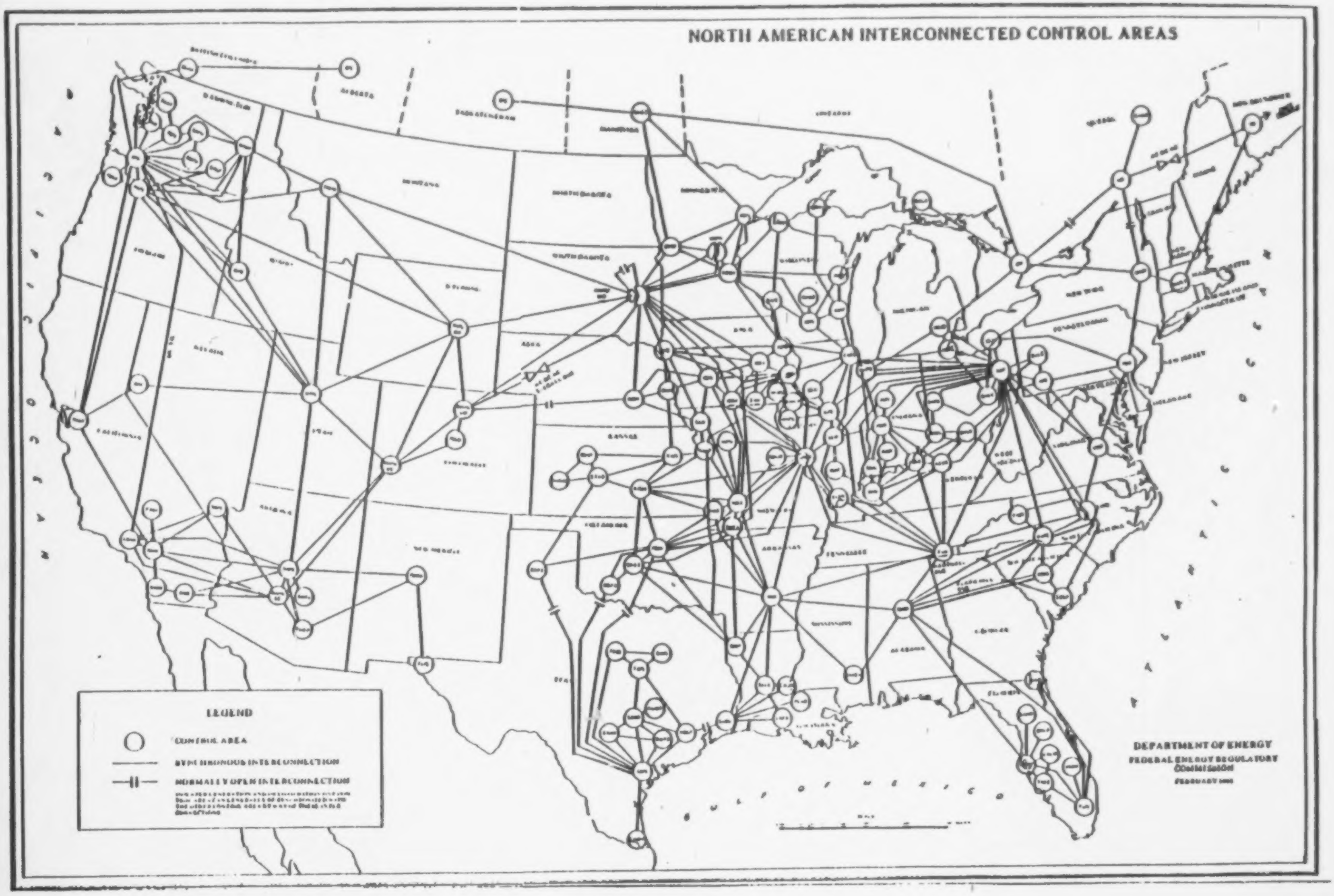

NORTH AMERICAN INTERCONNECTED CONTROL AREAS
PACIFIC OCEAN
ATLANTIC OCEAN
GULF OF MEXICO
LEGEND
CONTROL AREA
SYNCHRONOUS INTERCONNECTION
NORMALLY OPEN INTERCONNECTION
DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION
FEBRUARY

Figure II-2

or forced outages. The specific conditions under which economic dispatch is to be feasible would depend on a number of factors, including:

- the cost of additional facilities needed to remove the transmission limitation;
- the likelihood of the contingency;
- the probable duration of the contingency; and
- the economic penalties which would result from deviating from economic dispatch.

Most often, systems are planned to operate with economic dispatch under any single contingency, that is with the loss of any one element. Some multiple contingencies may also be contemplated.

In system operation, the problem is different:

- The fundamental criterion is to achieve economy within the established reliability constraints aimed at maintaining continuity of service. Economy of operation will be modified as necessary to maintain adequate system reliability and resulting continuity.
- The operator is limited to the use of those facilities which are installed and available at the time (not undergoing maintenance, and not out of service because of forced outages). He can only operate those generators which are connected to the system; other units would require time periods ranging from a few minutes to several days to be placed in operation.
- Service reliability requires that the system should be able to continue functioning without overloads, excessive voltage drops, or instability even if any single component should fail without notice due to equipment breakdown, lightning strikes, etc. This is called the principle of "n-1 operation," and it applies at all times, even when some elements are already out of service. For example, if three lines are out of service, the system's operation must be adjusted so that it will be able to stand the loss of a fourth line.

Thus, transmission limitations in system operation change whenever a component of the system fails, is taken out of service, or is returned to service. The location of transmission limitations will also change due to variations in generation output and area loads.

4. *Overall National Picture*

The pace of transmission construction in the United States has slowed steadily over the last few years. Figure II-3 shows the ten-year forecasts of transmission additions of U.S. and Canadian utilities from 1984 through 1987. For each year, the amount of transmission planned to be built in the United States in the next ten years has been reduced. There has not been as significant a trend in Canada as in the U.S. There are many possible reasons for this trend. One of them may be the decrease in the amount of utility-planned generation over the same period. However, there may be other reasons such as the difficulty of getting lines built due to siting and other environmental requirements, and a reluctance to take the risks involved in building transmission, when after taking these risks, the owner may be forced to make transmission capacity available to competitors for their transactions.

B. Technical Limitations to Transfers

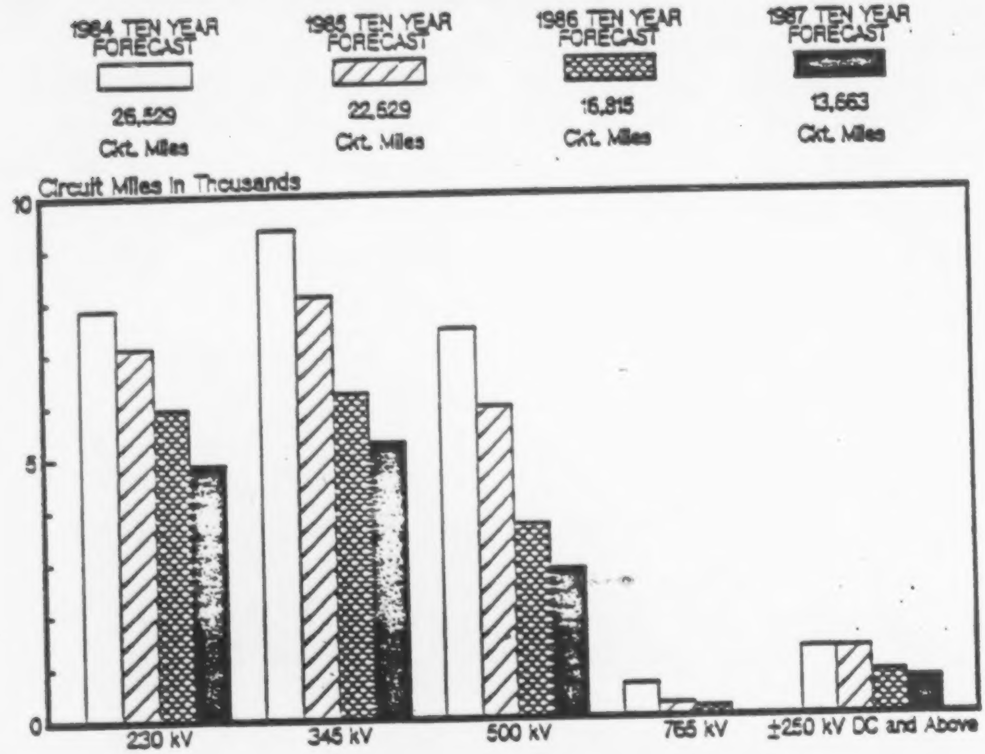
The technical limitations to transfers are related to the need to maintain reliable service and prevent damage to the transmission equipment. Each component of a transmission system, in particular, transmission lines and transformers, have individual limitations on their capability to carry power. However, the system as a whole has its own limitations which are considerably less than the sum of the limitations of individual components.

1. *Individual Line Constraints*

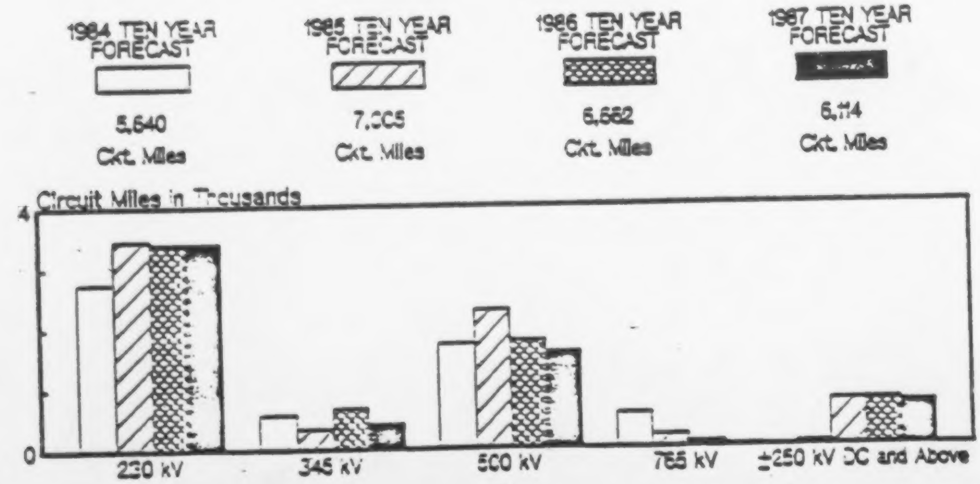
Every transmission line has a limit on the amount of power that it can transmit. One of the factors that causes the limitation is a thermal consideration. Current causes heating in the conductor. Excessive current may heat the conductor to a point at which the metal characteristics are affected, leading to brittleness and a shortening of expected life. In other cases, overheating of the conductor may cause the wires to sag excessively, bringing them too close to the ground and creating a

FIGURE II-3

PLANNED TRANSMISSION ADDITIONS
NERC-U.S.



NERC-CANADA



Source: 1987 Electricity Supply and Demand, Page 61, North American Electric Reliability Council (NERC) safety hazard. At other times, the thermal limitation may affect a relatively minor element of the transmission line: a disconnect switch, a wave trap at one of the terminals, or some metering equipment.

A thermally overloaded component will reach its critical temperature within seconds, minutes, or hours, depending on its previous temperature, its physical characteristics, and the amount of the overload. Therefore it may be able to carry a heavy current for a short time, a lesser one for a longer time, and a still lesser one indefinitely. The latter current will be treated as a "normal" rating, applicable to operation without contingencies. "Emergency" ratings are currents that can be carried for shorter times, on the assumption that the loadings can be relieved by changes in generation dispatch within the assigned time period.

Thermal ratings are usually established for loadings occurring for different periods of time - 10 minutes, 30 minutes, 4 hours, etc. Significant variations in the rating of identical physical transmission facilities are possible. These differences may be due to:

- The electrical/physical characteristics of the equipment including equipment cooling, etc.;
- The ambient weather conditions including temperature, insolation, and wind speed;
- The loss-of-life considered acceptable by the utility for the transmission equipment;
- Seasonal weather variations;
- Expected circuit load and loss factors;
- The type of contingencies that it is reasonable to assume;
- The impact of a generation contingency versus a transmission contingency;
- The duration of the loading, due either to the contingency or the type of transfer that may be considered;
- Availability of potential adjustments for generation redispatch and changes in system configuration; and
- Expected loading conditions prior to the contingency on that circuit.

2. *System Constraints*

The transmission system consists of many components which are interconnected with each other in a very complex way. The limitation on how much power can be transferred from one area to another by the transmission system is the smallest power transfer at which one of the components reaches its individual thermal rating, or at which any portion of the system reaches a voltage constraint or a stability limit.

Voltage limitations apply when, as a result of heavy power flows, the voltage at the receiving area reaches a minimum acceptable level and cannot be raised by increasing voltage in the sending area. Because of the complex relationships between voltages at all points in the transmission system, voltage limitations must be treated as system problems, rather than associated with one specific component.

Stability limits are of two types: steady state and transient. In a normally operating system, all generators operate in synchronism, i.e., at exactly the same speed. A small disturbance increasing or decreasing the speed of one generator will cause small changes in power output which will tend to bring that generator back to the common speed of the system. Steady-state instability is a condition in which, as a result of excessive power flows, this stabilizing process does not occur, and some generators speed up with respect to the others, causing the transmission system to "fall apart." Transient instability is a more common phenomenon, in which a similar loss of synchronous operation results from a severe disturbance such as a short circuit and loss of a transmission line, or the sudden loss of a generator or of a large load. (The loss of individual generators or transmission lines are relatively frequent events; as a result of system design and operating practices, however, they rarely affect service to the customer.)

In summary, transmission capability may be limited by thermal, voltage, or stability constraints. These may be close together so that relief of one constraint may only increase the system capability by a small amount. Similarly, a constraint due to one particular outage contingency may be close to a constraint due to a different contingency. Thus a substantial investment to relieve the most critical constraint may not result in much improvement. Also the construction of an additional line may improve the system's capability by only a fraction of that line's individual capacity.

3. *Interrelationship of Constraints*

The transmission capability of a system may be limited by normal or emergency considerations. In the former case, the limitations occur in the system as it is configured. Either one or more components have reached their thermal limit, or the system as a whole reaches a voltage limitation or a stability limit. However, most of the time, the limit on the transmission capability concerns a possible contingency. For example, calculations may show that with a system carrying a given amount of power, if a specific line were to trip out, another line would be loaded beyond its emergency rating. Since the operating rules require that the system must be able to supply service even if any one component should fail suddenly, the system may not be loaded beyond such a contingency limit. Thus the transmission system's capability of carrying power is limited not by the actual flows, but by the flows that would exist if a given contingency should occur.

For example, the very simplified system in Figure II-4a shows three lines linking the generator on the left to the load on the right. Because of different path lengths, the total power transmitted divides unequally on the three lines. In the example, it is assumed that the division is in the ratios of 10:9:8. Each individual line is capable of carrying 100 MW. With all lines in service, when Line A carries its rated power of 100 MW, the total power transfer is 270 MW because Lines B and C carry only 90 MW and 80 MW respectively; any attempt to transmit more power would increase the loading on all the lines and overload Line A.

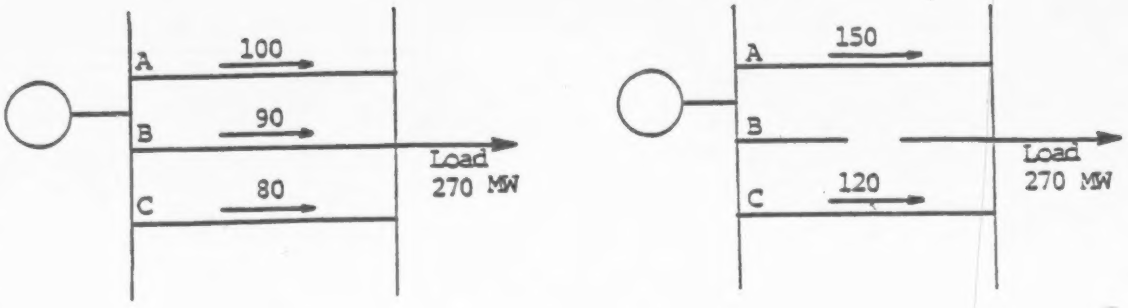
However, the safe transmission limit is much less. If Line B were to trip out, Line A would be loaded to 150 MW and Line C to 120 MW (see Figure II-4b). In order to prevent an overload under the "n-1 operation" principle, the power transfer must be reduced to 180 MW. Then the normal loadings are limited to only 67, 60, and 53 MW respectively (Figure II-4c) and the emergency loadings do not exceed the rating of 100 MW (Figure II-4d). The three 100-MW lines form a system capable of safely carrying only 180 MW.

100 →

A line = 100
B line = [illegible]

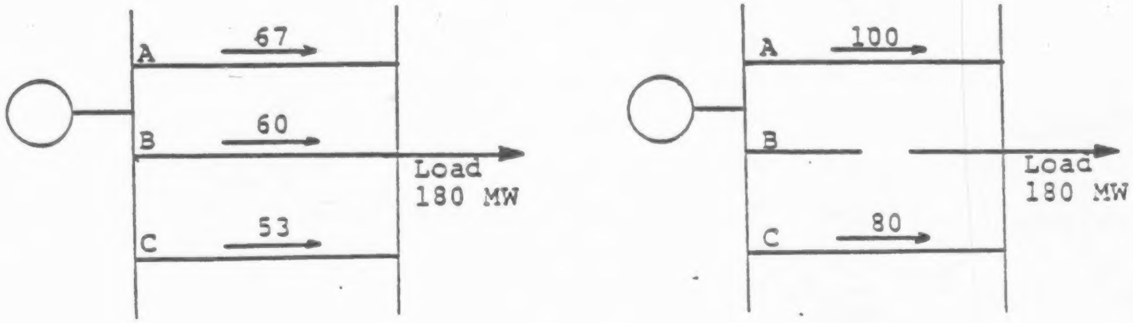
FIGURE II-4

TRANSMISSION SYSTEM LIMITATIONS (ALL LINES RATED 100 MW)


A
100
B
90
C
80
Load
270 MW
A
150
B
C
120
Load
270 MW

(a)
All lines in service.
System loaded without considering contingencies.
Line A at rated loading.

(b)
Outage of Line B
System loaded without considering contingencies.
Lines A and C overloaded.


A
67
B
60
C
53
Load
180 MW
A
100
B
C
80
Load
180 MW

(c)
All lines in.
System loaded to "n-1 contingency limit"

(d)
Outage of Line B
System was loaded to "n-1 contingency limit" before Line B tripped.
Line A at limit. No overloads.

4. *Preventive and Corrective Modes*

The concept of "n-1 operation," was defined earlier as operating in such a way that after any single contingency, the transmission system would still be within, at least, emergency ratings. This mode of operation is sometimes referred to as "preventive" to indicate that all provisions to protect the system are taken before any contingency occurs. Preventive operation is the rule in the great majority of utilities in the United States. It provides the best reliability of service.

There are, however, some situations in which the preventive mode is not applied, and the system relies on immediate automatic action after the contingency occurs to prevent overloads that will damage equipment or threaten human safety, or excessively low voltages that would cause damage, or malfunctions, to utility or consumer equipment. Such a mode of action is referred to as corrective, remedial, or reactive. Corrective action might involve such measures as tripping a generator, shedding some customer load, or rearranging transmission by connecting two buses together, when a specific contingency occurs. It would be used when preventive mode operation would entail a heavy economic penalty. It is much more common in the western part of the United States than in the east, but is increasing in use everywhere.

Corrective action is less common than preventive operation because it is considered more risky to depend on action after the fault. An accumulation of different corrective actions for different contingencies is considered even more risky because malfunctions of these schemes could have consequences that are hard to predict, including the possibility of causing interruptions when no hazardous conditions exists.

5. *Need for Reserves for Emergencies*

In order for the system to be operated safely, it must have reserve capacity both in the generation and the transmission facilities. This principle applies both in the operation and the planning of the system. The absence of sufficient reserves exposes the system to service curtailments in excess of the levels considered reasonable, to major system disturbances or "blackouts," or to unfair dependence on neighboring systems.

In operating the system, it is necessary to provide generation reserves capable of providing additional power if any generating unit, or an entire plant, were to be lost. Since the time required to start up a unit ranges from minutes to many hours, depending on the nature of the unit, this reserve capacity must be available immediately or on very short notice, and is referred to as "operating reserves." Some of the operating reserves must be actually connected to the system as "spinning reserves." Some systems will permit a portion of the reserve to be in the form of quick-start operating reserves consisting of units capable of being started and connected in a matter of minutes.

System operation also needs reserve capacity in the transmission system. These reserves are represented by the difference between the capacity needed to satisfy current conditions, and the facilities needed to operate under the "n-1 operation" criterion.

In the planning of the system, it is necessary to provide reserves not only for the requirements of actual operations, but also to allow for scheduled maintenance to be performed on the generation and transmission system components, and also to allow for the possibility that actual loads may turn out to be greater than those forecasted. Such reserves are called "installed reserves." Some, or all installed reserves are not operated when the combination of electric use levels, including system exports, and generation forced outages are low.

C. Temporal and Economic Factors Affecting Constraints

Transmission limitations have been shown to involve the interplay of the physical characteristics of the system and the actual flows. Both of these change with time and with economic conditions - and economic conditions also change with time. As a result, the amount of power that can be safely transmitted between two areas keeps changing.

1. *Pattern of Demand*

The customers' loads vary constantly. Much of the time variation can be ascribed to cycles of nature (time of day, season of the year) and of human activity (day of the week). Other changes are due to changes in economic activity which happen in irregular cycles, or to weather conditions, changes in fuel costs and electric rates and random events which are not cyclical at all.

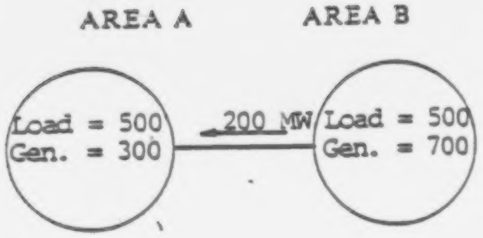
A striking real-life example of power transfers changing with a temporal cycle can be seen in the transmission between the Pacific Northwest and California. The Northwest has a peak load in the winter, due to electric heating; California's peak load is in summer, with air conditioning an important component. The transmission system joining them generally sends power north in the winter and south in the summer. (In addition, considerable transfers occur because of temporal variations in the availability of hydroelectric energy as discussed later.)

As the loads change, the power generated in each area of a system also changes, but not necessarily in proportion. Instead, the generation at each plant changes according to its incremental cost of generation, in such a way as to minimize the total generation cost of the utility. As the total system load increases, for example, the generation at a given plant may increase a lot, a little, or not at all. The transmission system which joins the different areas carries the net difference between the generation and the load of each area. Thus, the power transmitted between any area may increase, decrease, change direction, or remain the same, as the loads change. Power transfers in some lines may actually be greater in medium or low-load periods than at peak times. Figure II-5 illustrates such a case. At light loads, the net power transfer for economic dispatch is 200 MW from area B to area A. At a higher load level, area A generation has increased more than that of area B, and the flow between the areas has both reversed and decreased in amount.

2. *Weather*

The weather affects constraints on transfer capacity both indirectly, by affecting loads, and directly, by affecting the capacity of individual components.

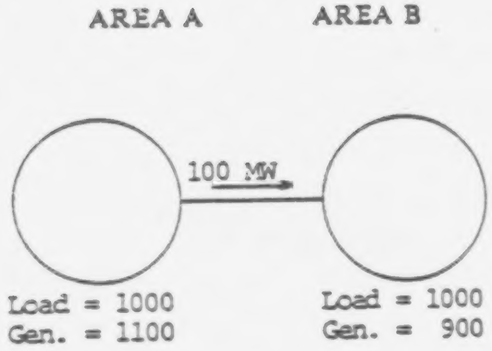
FIGURE II-5


AREA A
AREA B
Load = 500
Gen. = 300
200 MW
Load = 500
Gen. = 700

INCREMENTAL PRODUCTION COSTS

Area Generation	Area A Generation	Area B Generation
300	25	20
700	30	25
900	35	40
1000	37	50
1100	40	60

a. Light Load Period. System Incremental Cost = 25 $/MWH


AREA A
AREA B
100 MW
Load = 1000
Gen. = 1100
Load = 1000
Gen. = 900

b. Heavy Load Period. System Incremental Costs = 40 $/MWH

The effect of weather on loads is complicated by differences in weather in different locations; this is another reason why economic power interchanges may increase or decrease as the weather changes. In the summer, power will flow more heavily towards an area which is suffering from a heat wave from neighboring areas with milder weather.

In addition, weather conditions directly affect the capability of individual components of the power system, and, as a result, that of the transmission system. Warm weather reduces the effective capacity of most thermal generation sources. The energy as well as the capacity of hydro resources depend on seasonal precipitation and evaporation patterns, and by competing uses for the water. The thermal capacity of transmission lines varies with the ambient temperature; when the weather is hot, it takes less current to heat conductors to a given maximum permissible temperature, so that many utilities use lower ratings in summer than in winter.

Extreme weather conditions may actually disable certain components. Lightning is the primary cause of transmission line failures, and extreme cold weather has interrupted the flow of coal supplies for some generating stations, thus restricting their production and causing other stations to increase theirs.

3. *System Configuration*

The transmission system's transfer capability is affected by changes in the configuration of the transmission and generation systems, which may be due to maintenance, to transmission and generation forced outages, or to the deliberate switching of transmission system components. Every time that a component is added to or taken out of the system, for whatever reason, the operator is dealing with a new system; the actual flows change, and so do the potential effects of any contingencies. A different contingency may become the limiting one, and the total transfer capability may change very substantially.

4. *Production Costs*

Variations in production costs, whether caused by changes in fuel cost or by any other causes that do not apply equally to all sources, result in decreases in the output of those generators whose costs increase more than the others', and subsequent increases in the output of the other generators. The basic economic flows in the transmission system change as a result. This in turn changes the constraints on the capacity of the transmission system to carry power for economic transactions and emergencies.

The changes in relative costs may have many causes:

- Fuel price fluctuation;
- Availability of competing power sources from neighboring electric systems;
- Variations in hydro conditions which change the amount of available hydro energy; or
- Shortages of specific fuels due to various reasons.

Before the 1973 oil supply crisis, the effective costs of coal and oil were reasonably balanced. The relative production cost of steam units depended more on the efficiency of their design (often a matter of age) than on the fuel they burned. The mid-western region, near coal mines tended to burn coal; the northeastern and Atlantic states burned more oil. Incremental fuel costs were reasonably balanced, and the economic power flows between the Midwest and the East were related as much to temporary situations such as unit outages and load variations as to basic cost differentials. There was some constant west-to-east flow because some eastern utilities participated heavily in "mine-mouth" coal plants in western Pennsylvania. Beginning about 1973, however, the cost of oil began to soar relative to that of coal. A permanent cost differential arose between the Midwest and the East; transmission between the two has ever since been fully loaded almost all the time in order to carry power from the low-incremental-cost Midwest to the high-incremental-cost East.

5. *Loop Flows*

When one utility, or area, sells power to another, this transaction is implemented by the seller increasing its generation and the buyer decreasing its generation by an equal amount. The effect is that flows increase along all the paths between the two parties, regardless of ownership of the lines, and including indirect paths through third parties. The distribution of the increase in flows depends on the impedance of the various paths (impedance is a characteristic of a transmission line, and depends on the line's voltage, length, and design details). A path with a low impedance will pick up a greater part of the total transfer than a path with a high impedance.

Some pools, recognizing that power flows are governed by physical laws, and with the assumption that all parties would share fairly in terms of contributions made and benefits received at different times, have instituted "free-flowing" ties among themselves. They do not charge each other for the use of the transmission they own in interchanging power among themselves.

However, in the absence of a specific "free-flowing tie" agreement, it is the practice in many regions of the country that two utilities will not schedule the transfer of a block of power between them unless they establish, through ownership or leasing or purchase of transmission service, a "contract path" of sufficient capacity leading from one to the other. While this concept at least ensures that the total scheduled transactions between two systems do not exceed the sum of the individual capacities of the lines linking them, it does not at all ensure that the total flow is within transmission limitations as they have been explained earlier in this section. The transmission limits between two areas are always less than the sums of the capacities of the individual lines linking them, for three reasons:

- The fact that power flows according to line impedances and not according to line capacities;
- The fact that some lines have higher capacities than others, but do not draw current in proportion; and
- The need to load lines at less than their emergency ratings to provide for increased flows due to possible contingencies.

When two or more paths carry power flows different from the amounts assigned to various contract paths, the difference is often referred to as "loop flow," because the difference is in one direction on some paths and in the other direction on some others. Loop flow is the result of many different transactions going on at the same time.

Since all control areas in the U.S. are connected directly or indirectly to many others, the same physical laws will cause part of the transactions between two adjacent areas to flow through the transmission systems of third, (and fourth, etc.) parties. These generally unwanted flows are also referred to as "loop flows," or sometimes "circulating flows," or "unscheduled flows." Figure II-6 shows some control areas in WSCC, with their loads, generation, and interchange at one instant in time. The circulating flows (CF) in each link are the differences between the actual interchange (AI) and the scheduled interchange (SI) between the control areas involved.

A line which carries circulating current due to other parties' transactions cannot be fully used for the owners' transactions. Loop flows are an important aspect of the operation of both the WSCC system to which SCE belongs, and the PJM Interconnection.

Figure II-7 illustrates loop flows in the Northeastern U.S. when Ontario Hydro sells power to New York State. 50% of such a transaction can flow through PJM lines. On the other hand, a PJM west-to-east transaction will, in part, flow through the Ontario-New York paths, which tends to reduce the effect of the west-to-east loop flow on the PJM lines. However, the two effects are rarely completely cancelling, and the net result is a decrease in the effective transmission capacity available for west-east transfer within PJM, which varies with the amounts of the transactions between all the parties involved.

Figure II-8 shows loop flows in the WSCC system. The transmission between the Pacific Northwest, the Mountain states, and Arizona and California has been described as a "doughnut" which carries considerable loop flows in addition to scheduled flows. These loop flows depend on the transactions between the various parties, and vary in amount and in direction; sometimes they go clockwise, and sometimes counterclockwise. At all times, they affect the amount of power that can be safely transmitted between two parties in the system.

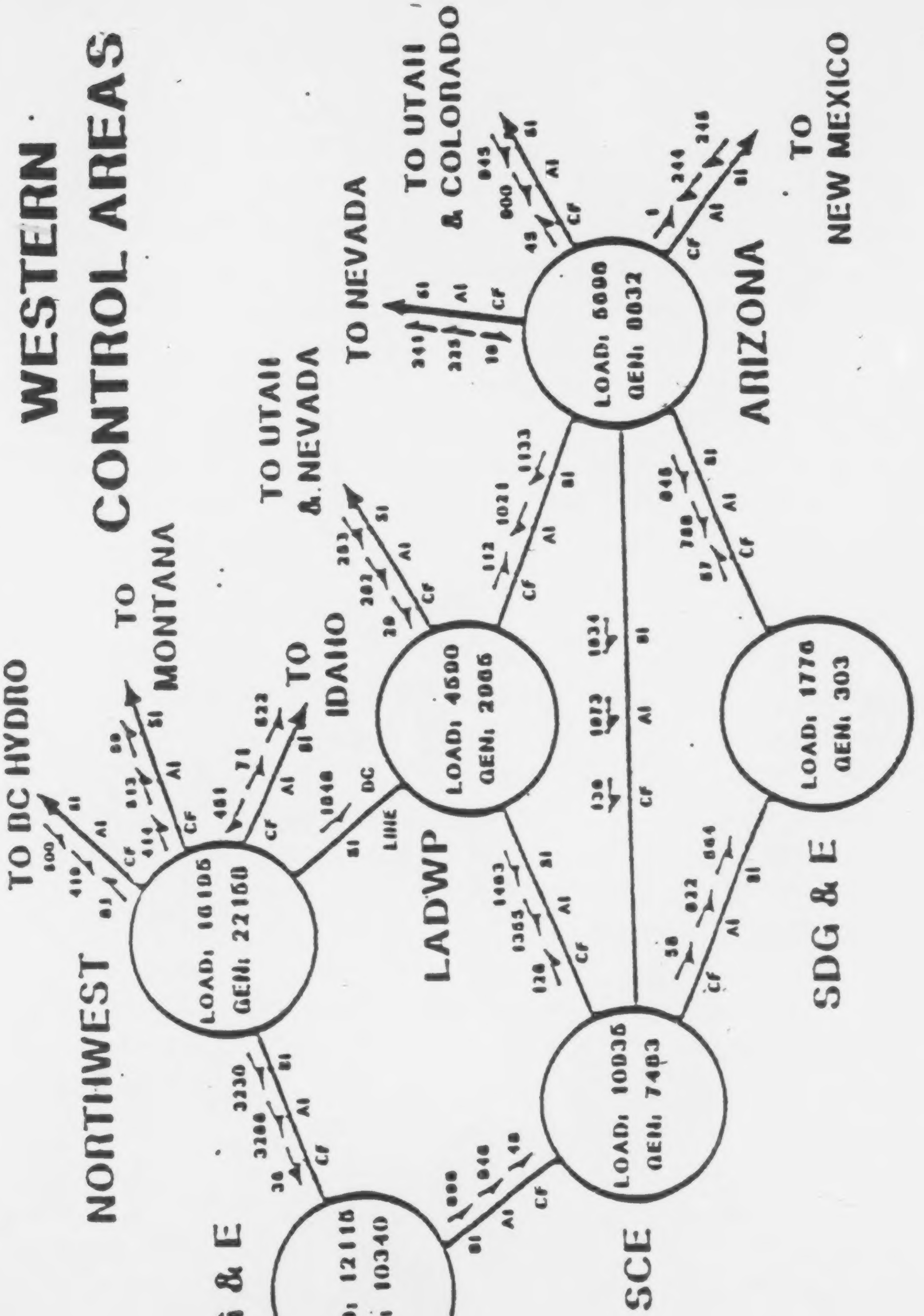
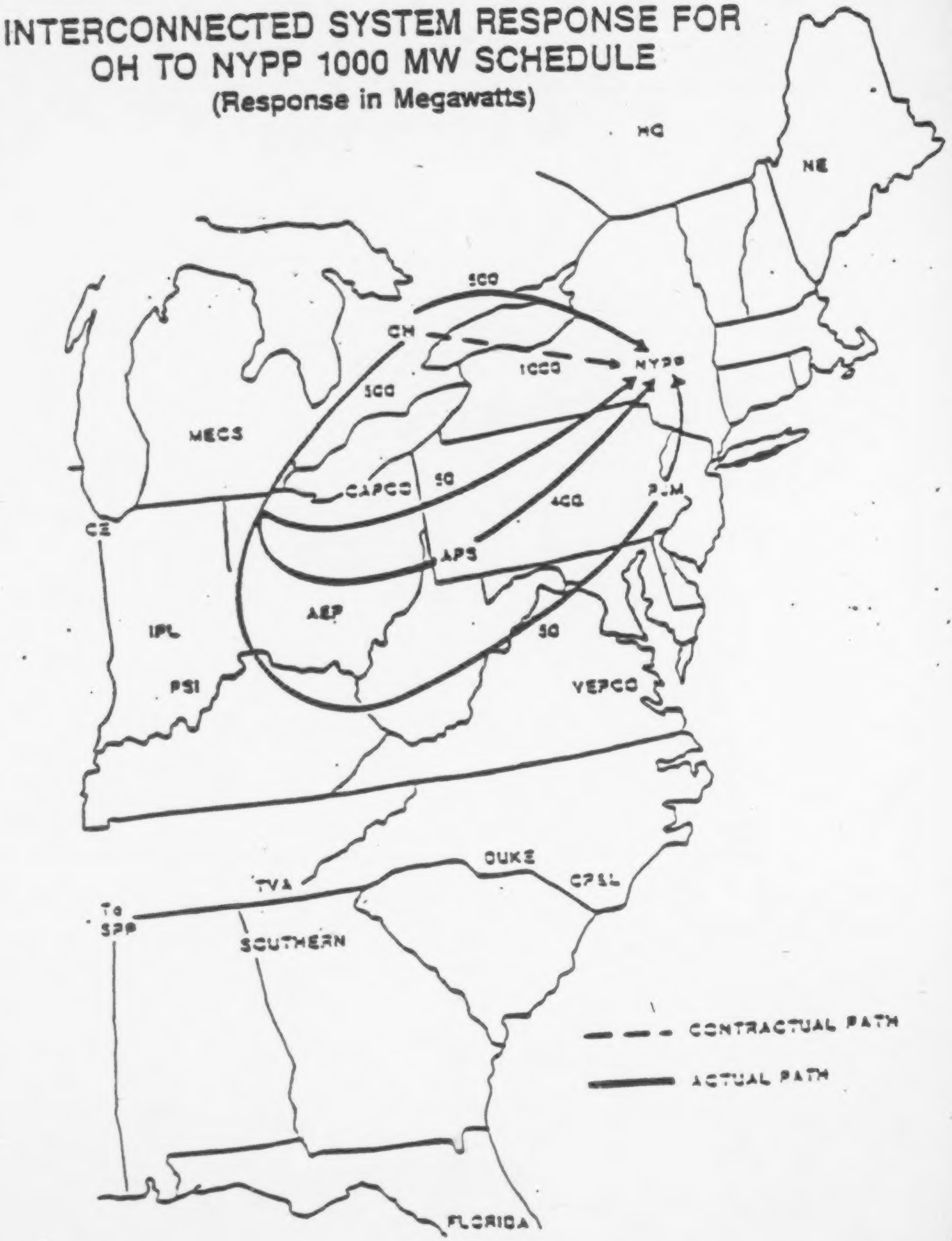

WESTERN CONTROL AREAS
PG & E
LOAD: 12118
GEN: 10340
NORTHWEST
LOAD: 16105
GEN: 22150
SCE
LOAD: 10036
GEN: 7483
LADWP
LOAD: 4500
GEN: 2066
SDG & E
LOAD: 1776
GEN: 303
ARIZONA
LOAD: 5000
GEN: 0032
TO BC HYDRO
TO MONTANA
TO IDAHO
TO UTAH & NEVADA
TO NEVADA
TO UTAH & COLORADO
TO NEW MEXICO
DC LINE
CF
AI
SI

FIGURE II - 6
CONTROL AREA ILLUSTRATION

FIGURE II-7

INTERCONNECTED SYSTEM RESPONSE FOR OH TO NYPP 1000 MW SCHEDULE
(Response in Megawatts)


HQ
NE
500
OH
1000
NYPP
500
MECS
CAPCO
50
400
PJM
CE
APS
AEP
IPL
50
PSI
VEPCO
DUKE
TVA
CP&L
To SPP
SOUTHERN
FLORIDA
CONTRACTUAL PATH
ACTUAL PATH

Clockwise Loop Flow

Montana/Wyoming Coal Schedules to the Northwest Schedule: 1000 MW

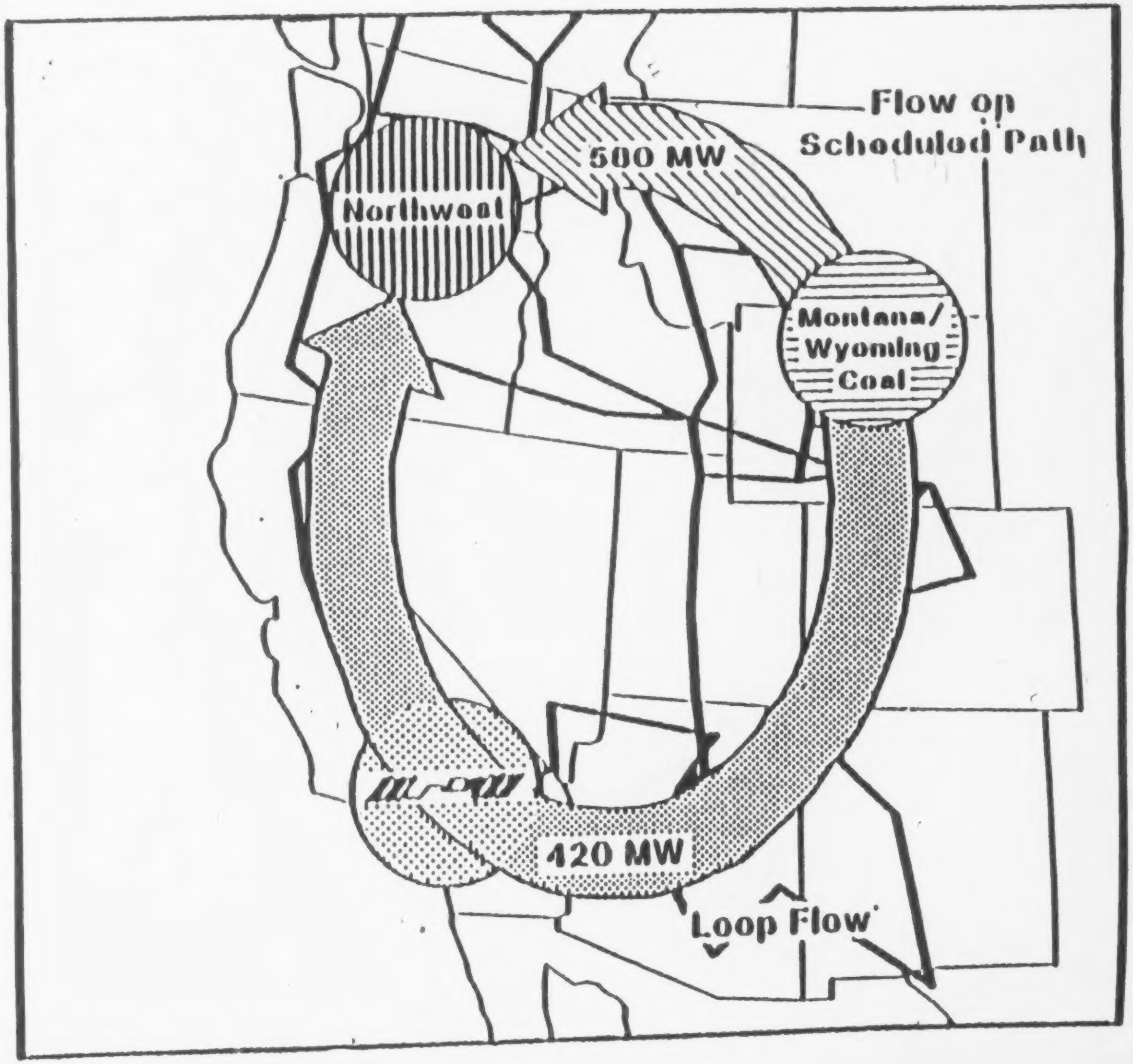

Flow on Scheduled Path
500 MW
Northwest
Montana/ Wyoming Coal
420 MW
Loop Flow

FIGURE II - 8

6. *Consequences of Temporal and Economic Factors*

All the temporal and economic factors that have been discussed have one thing in common: they cause the effective capability of the transmission system to carry power between two areas to vary. Some of the factors are reasonably predictable, and some are not. Neither the "contract path" concept, nor any other method, can guarantee that a transaction that can be made reliably on one day (or at one hour) can be reliably carried out at another time. The transmission system needs to be constantly supervised and controlled for reliable service to all users. When an unsafe situation happens, the operator of the transmission system must have the right and the technical means - controls and communications - to correct it; the correction most often consists of increasing the production of some generators and reducing that of others. Utilities, working together, have developed rules for indemnifying a party who may bear the brunt of adjusting power flows for the sake of reliable service for all parties using the transmission system. The essential point is this: when the transmission system is directly or potentially overloaded, the system operator gives instructions for the relief of the system and these are followed at the expense of economics. Economic adjustments are made afterwards.

Until recently, non-utility generation (NUG) has been a relatively small portion of the total generation supply. If a NUG was not under control of the system operator to the extent that a similar utility-owned unit would be, it did not matter much because the effect was small. As the proportion of NUGs becomes substantial, however, the need for their control and cooperative operation as participants in the overall electric system becomes critical. SCE, which contains a high and growing proportion of NUG resources, reports a number of problems in this area and expects more in the future. The integration of the NUGs into the system, taking their full share of its obligations, will be indispensable if the reliability and economy of the entire system is to be preserved.

III. BASIS AND APPROACH FOR CASE STUDIES

A. The Five Scenarios

The effects on utility planning and operation of five scenarios of regulatory change were studied. The five scenarios are as follows:

Scenario 1 - Status Quo Plus Rolling Prudency Reviews

Scenario 1 continues the existing regulatory scheme and electric power industry structure and reaffirms the regulatory-utility bargain with minor modifications of regulatory rules and procedures to improve the ability of utilities to attract capital for construction of new facilities and to assure a reasonable return to investors (e.g., "rolling prudency reviews"). Modifications of PURPA rules to correct perceived imbalances in avoided cost pricing rules for QF power would also be allowed. Many utilities will continue to rely on QFs and IPPs for a portion of new power needs. Transmission access would remain on a voluntary basis to be negotiated between the participants. FERC would retain its authority over transmission rates and wholesale power sales.

Scenario 2 - Expanding Transmission Access in the Existing Institutional Structure

In this scenario, the number of bulk power sellers and the number of potential bulk power buyers is increased by 1) removing some of the size, technology, fuel, and ownership limitations for qualifying facilities through legislative modifications to PURPA and the Public Utility Holding Company Act; and 2) changing the mandatory transmission access provisions of the Federal Power Act to a broader public interest standard to make utilities and large retail customers eligible to apply for mandatory wheeling orders. Policies intended to encourage bulk power sales and wheeling will be continued and expanded. The IPPs and QFs would be assured a market under the States' implementation of PURPA.

Scenario 3 - All Source Competitive Bidding for New Generation with Mandatory Wheeling

Scenario 3 establishes an institutional structure to allow all source competition for new bulk power supplies with market based pricing. (The scenario is loosely based on the Keystone and Hesse proposals.) Transmission access is included as a prerequisite for participation in the competitive system. Mandatory transmission access under the public interest standard of Scenario 2 is also available for bulk power transactions by utilities. Provision of wheeling services to retail customers remains voluntary. Utilities are able to participate in "bidding" for new capacity within their own service territories and those of other utilities with appropriate safeguards established by the states to limit problems of self-dealing, conflict of interest, etc.

Scenario 3 creates a two-tiered bulk power supply system: new power supplies under a minimally regulated, "workably-competitive" market; and existing generation remaining under current state-federal scheme of regulated entry and pricing. The electric power supply industry will gradually evolve to an all competitive generating sector as existing plants are replaced. Transmission and distribution services remain regulated as at present.

Scenario 4 - Generation Segregated From Transmission and Distribution Services

Scenario 4 would create a competitive system for electric power supplies. Existing and new sources would compete to sell power to regulated transmission and/or distribution companies. Integrated utilities would be required to segregate generation activities both institutionally and operationally from transmission and distribution through creation of separate subsidiaries or corporate divestitures. Transmission and distribution activities would be heavily regulated. Modifications to PURPA QF requirements and PUHCA restrictions allow broad participation in generation markets. Local distribution companies would be primarily responsible for securing adequate power supplies from competing supplies.

The transmission company would provide wheeling services for utilities under regulated rate schedules and could also act as a power broker linking local distribution companies with power suppliers. Distribution companies could obtain mandatory transmission orders from FERC on a public interest standard. There would be no mandatory wheeling for retail customers, but it is expected that generators and transmission companies would engage in direct sales to large retail customers, with local distribution companies providing distribution wheeling on a voluntary basis and receiving bypass or standby payments.

Scenario 5 - Common Carrier Transmission Services in a Disaggregated, Market-Oriented Electric Power Industry

The electric power industry is divided into institutionally separate generation, transmission, and retail distribution segments. The major difference between this scenario and scenario 4 is that separate transmission companies would explicitly be required to provide transmission services as a common carrier - i.e., non-discriminatory service based on approved wheeling tariffs - to all parties requesting service including large customers. The transmission company would have an obligation to provide adequate transmission capacity.

Distribution and transmission services would remain regulated, but in the electric generation segment, market entry and bulk power pricing would primarily be left to market forces. Federal and state policies might encourage greater aggregation in transmission services to create coordinated large regional transmission systems; either through mergers and acquisitions or through operational agreements among neighboring systems.

The five scenarios are summarized in Table III-1. The procedural changes and system technical changes, including reinforcements, which would be required with each scenario, were determined. As discussed earlier, the overall objective was to maintain the reliability presently being achieved in its planning and operation and the savings presently being achieved in the operation of the system through coordination procedures within the system and with other utilities. This essentially meant estimating what technical system and procedural changes would be required to maintain the existing reliability and coordination benefits to consumers as they

TABLE III-1
OVERVIEW OF SCENARIOS FOR DEREGULATION AND TRANSMISSION ACCESS

	SCENARIO 1	SCENARIO 2	SCENARIO 3	SCENARIO 4	SCENARIO 5
	- Strengthen the Regulatory-Utility Bargain with "Rolling Prudency Reviews." - QFs and IPPs can sell only to utility.	Expand Transmission Access to QFs and IPPs to Sell to Utilities and to certain Large Retail Customers	Competitive Bidding Required for All New Utility Generation. No transmission access to customers.	All-Source Competition for All Bulk Power Supplies, with Generation Segregated from Transmission and Distribution Services	Common Carrier Transmission Services in a Disaggregated Market-Oriented Electric Power Industry - Anyone Can Generate - Anyone Can Buy From Any Supplier
INDUSTRY STRUCTURE	- Vertically integrated - IOUs, Municipals, Cooperatives, Federal Systems continue as present	Same as 1 plus - unregulated utility subsidiaries	Same as 2 plus - utility subsidiaries compete in other utilities' bidding.	Generation segregated. Regulated transmission and/or distribution companies.	- Generation segregated. - Transmission regulated as common carriers. - Regulated distribution companies.
GENERATORS/SELLERS	Generation: - by Utilities - by QFs (a la PURPA) - by IPPs (at utility's option, or as per state commission selling to utilities) All sales are to utilities. Self-generation still possible.	Generation: - by utilities - by QFs (PURPA but fewer restrictions) - by IPPs - unregulated utility subsidiaries/affiliates	Generation by: - utilities - QFs - same as 2 - IPPs - same as 2 Competitive bidding required (including non-price factors in evaluation). - Utility can be a competitor in own system. - Utility can form unregulated subsidiaries to generate in other systems.	Generation by: - Utilities - QFs - IPPs All competing for sales to T&D utilities. Any generator can sell to retail customer but no mandatory wheeling. Distribution companies plan for requirements. Transmission companies may buy and broker power.	Same as 4. Any generator can sell to any buyer.
BUYERS (Other than from regulated utilities)	- Present customers buy from local utility unless the local utility agrees otherwise. - Utilities are only customers of non-utility generation.	Utilities and large retail customers may apply for mandatory wheeling orders under a "broader public interest standard."	Same as 2, but excluding large retail customers.	T&D Utilities. Large retail customers.	- Any customer can buy from any generator. - Transmission Company must provide transmission.
TRANSMISSION ACCESS (Wheeling)	Essentially voluntary - by mutual agreement. FERC can order when requested under PURPA rules.	Utilities and large retail customers can petition FERC for mandatory wheeling orders for non-local generators based on a new public interest standard.	Same as 2. Also: Mandatory wheeling under public interest standard for bulk power transactions by utilities. Utilities must give transmission access if they want to participate in the generation bidding.	Transmission divisions or subsidiaries provide wheeling for utilities under regulated rate schedules. No mandatory wheeling for retail customers (voluntary ok).	- Separate transmission companies must provide services to all parties. - Wheeling customers could contract for different levels of service.

TABLE III-1
OVERVIEW OF SCENARIOS FOR DEREGULATION AND TRANSMISSION ACCESS

(Continued)

	SCENARIO 1	SCENARIO 2	SCENARIO 3	SCENARIO 4	SCENARIO 5
REGULATION	- Rate regulation based on present methods. - Rolling prudency reviews used.	Same as present plus broader FERC authority for ordering wheeling and wider eligibility for QFs.	Same as Scenario 2, but entry and pricing regulation is replaced by all-source competition. - States mandate how competitive bidding is to be done. - Existing generation remains regulated. - Transmission and distribution remain regulated.	- All generation is unregulated. - Distribution and retail sales state regulated. - Mixed federal/state regulation of transmission capacity and services.	- All generation is unregulated except to assure competitive markets. - Distribution company/retail sales state regulated. - Transmission state/federal regulated as common carriers.
WHO DETERMINES WHAT IS BOUGHT AND SOLD?	- Utility decides amount and type of generation needed. - Regulated utility sells to customer. - QFs sell to utility at avoided cost, as defined by State Commission. - IPPs sell to utility by voluntary contracts.	Same as Scenario 1, plus purchases by large customers from NUGs.	Utility decides amount and type of generation needed. Competitive bidding under state approval results in regulated utility either generating its own or contracting from QFs, IPPs, or other utilities.	T&D company, or transmission company acting as broker, decides amount and conditions.	Distribution companies and large retail customers decide
SYSTEM RELIABILITY AND COORDINATION - Monitoring reserves - Maintaining reliability and system integrity - System regulation	- Responsibility of local utility/control center. - QFs, IPPs operational responsibilities are based on contract terms with the local utility.	Same as 1	Same as 2	- Responsibility of regulated transmission or T&D company. - Operational responsibilities of power supplies and local distribution companies as by contract.	Generation, transmission, and distribution company responsibilities specified by contract.
DISPATCH - Unit commitment - Unit loading - Maintenance coordination - Variations from scheduled transactions.	- Determined by the local utility for utility owned or leased units. - For QFs and IPPs, dispatch depends on contract terms with local utility.	Same as 1, except that trans-mission accessors not subject to utility control are covered by contract between generator and consumer.	Same as 2	Determined by contracts between power suppliers and transmission company, distribution company, or retail customers.	Same as 4

TABLE III-1
OVERVIEW OF SCENARIOS FOR DEREGULATION AND TRANSMISSION ACCESS

(Continued)

	SCENARIO 1	SCENARIO 2	SCENARIO 3	SCENARIO 4	SCENARIO 5
PRIORITIES - Who determines whose use of transmission is curtailed if there is not enough capacity for all transactions? (Applies to short-term planning, and to operation)	Local utility sets priorities under state supervision.	Same as 1 Emergency curtailment per state policies.	Same as 2	Same as above.	Same as 4
TRANSMISSION ADDITIONS	Responsible utilities make decisions. FERC can order new lines under PURPA rules.	Same as 1, but state may order utility to provide capacity for wheeling.	Same as 1 but state rules may require utilities to plan for instate wheeling and to consider regional transmission needs.	Transmission utility responsibility to provide adequate capacity for customers' wheeling. Transmission company may require adequate notice and some financial commitment.	Same as 4.

presently exist, with the various alternative deregulation and transmission access scenarios.

B. Factors Investigated and Basis for Selecting Case Studies

1. *Key Factors and Questions*

In performing the case studies, the following information was obtained and reviewed:

- The present capacity of the transmission system, both in the internal network areas and in the interconnection and interties to other systems in other regions;
- The critically loaded facilities and the critical contingencies determining the limitations in transfer capability;
- The system conditions causing maximum loading;
- Ways that the present transmission capability can be increased;
- Existing qualifying facilities or other non-utility generators;
- Potential future non-utility generators;
- The municipals, REAs, etc. that presently obtain power; and
- Also, any utilities for whom wheeling service is presently provided.

The analyses obtained answers to a number of key questions relating to operations of the systems.

a. What information will be required concerning generation schedules of non-utility generators and consumption of loads supplied by others? For what seasons, times of day, etc., will data be required?
b. How far in advance will this information be needed?
c. If additional transfers are needed by non-utility generators or large customers, how much advance notice would be necessary to provide for such changes in operations?
d. What changes in procedures are needed for handling the additional information requirements?

e. Who should be responsible for making the necessary operating decisions for coordinated operation of the overall system with the various scenarios?

f. How should the output of the various non-utility units be scheduled and controlled?

g. Is incremental cost dispatch feasible at present with existing NUGs?

h. Will the system be able to continue to perform incremental cost dispatch?

i. Who should determine the availability of transmission capacity?

j. If there is a shortage of transmission capacity among the various potential users, who should determine the priorities for use?

k. At what load levels are the greatest transmission restrictions anticipated?

l. How will the ability to control voltage and provide necessary reactive support be affected? How will this problem be handled?

m. How will the provision of spinning reserve and regulating capacity be changed with the advent of non-utility generators under the various scenarios?

n. How will the ability to maintain frequency control and tie line schedules be affected?

o. What changes in communications will be necessary with the various scenarios?

p. What special control technology will be required with increased transmission access under the various scenarios? Will contractual arrangements alone be sufficient to cover operations, or will the ability to physically control the use of transmission by the system operator will be necessary? What types of physical controls will be needed, and what should be controlled?

q. How will generator maintenance schedules be established and approved?

r. Will QFs and IPPs be eligible to participate in pool activities? Should they be?

s. What potential new technologies could be valuable in helping to meet the new operating requirements with the various scenarios?

t. What improvements are needed in the various types of control?

With regard to the effect of the potential scenarios and the planning of the future development of the electric system, the following key questions were asked:

a. What new data and procedures will be necessary in order to make load projections for the future?

b. How will the possibilities of losing loads and gaining loads through the competitive process made possible by transmission access be evaluated and treated?

c. How will the potential information needed for making your planning studies be obtained, concerning new generating sources both within and outside the utilities' systems including QFs and IPPs? What sort of data will be needed and how can it be obtained?

d. In planning transmission, would utilities provide for potential mandatory (or non-mandatory) wheeling requirements? How would they include this in their planning?

e. What changes in sites for future generation may result?

f. Would the systems' load projections be as certain as they were before? Would increased reserves be required to cover these uncertainties?

g. Would the service dates for future generating capacity additions be as certain as with present conditions? Would potential changes in construction schedules for QFs and IPPs be greater or lesser than the potential changes in the schedules for the utilities' own generation?

h. Would the reliability of the new units be as good or bad as the present utility units, and would greater or lesser reserve capacity be required?

i. How would utility commission involvement affect planning decisions?

j. Would lead times be increased or decreased? How would utilities' plans be affected because of the such changes?

k. Would reserve requirements be increased with the various scenarios and why?

l. Should planning criteria be revised and if so, why and in what direction?

m. In planning transmission, how would the additional transmission that may be required for future wheeling, either mandatory or voluntary, be determined and provided.

n. What changes would be required in the reserves provid d in the transmission systems?

o. What changes are foreseen in future additions to the transmission system?

p. What changes in planning procedures, pool activities, or reliability council activities would be required?

The potential for existing and/or new technologies to solve some of the technical problems raised by the new scenarios was carefully checked using the best of technologies given in Table III-2. Specific questions addressed were:

a. What new technologies are available to help maintain existing system reliability and existing inter-company coordination benefits with the addition of large amounts of QFs and IPPs and the ability of large customers to switch suppliers?
b. Are any new modeling approaches needed and possible?
c. Are any new types of system facilities possible?
d. If technical changes must be made to the transmission system, including possibly adding additional circuits, how should the investments required in these facilities be allocated among the various users?

2. *Criteria Used in Selecting Systems to be Studied*

A number of criteria for selecting the systems to be studied were reviewed and discussed. The criteria selected are shown in Table III-3. The transmission conditions in the various systems in the U.S. were also reviewed and summarized, as shown in Appendix A.

Based on this information, the systems selected were the Southern California Edison system (SCE) and the Pennsylvania-New Jersey-Maryland Interconnection system (PJM).

TABLE III-2

POTENTIALLY APPLICABLE MEANS OF OVERCOMING SYSTEM LIMITATIONS

1. Overcoming Line Limitations
    a. Voltage uprating
    b. Current uprating
        - Increase temperature rise
        - Sag assessment and monitoring
        - Dynamic conductor ratings
        - Resagging
        - Restringing (including bundling)
    c. New towers on existing rights-of-way
        - Underbuild or overbuild
        - Conversion to multiple-circuit towers
        - Higher phase order

2. Overcoming System-Related Limitations
    a. Load division among circuits
        - Phase angle regulators
        - Series reactance or capacitors
        - System reconfiguration
        - HVDC
        - Redispatch of generation
    b. Voltage profile limitations
        - Reactive power management
        - Shunt capacitors
        - Series capacitors
        - Static VAR compensators, synchronous condensors
        - Transformer tap changing under load (LTC)
        - Line sectionalizing

3. Overcoming Transient and Dynamic Stability Limitations
    - Reducing clearing time
    - Series capacitors
    - Rapid adjustment of network impedance
    - Generator tripping and fast runback
    - Fast valving
    - Braking resistors and load switching
    - High-speed reclosing
    - Advanced excitation systems and stabilizers
    - Transient excitation boost
    - Fast acting phase angle regulators
    - Generator reactors
    - SVCs and synchronous condensors
    - Adding switching stations (sectionalizing)
    - Special switching schemes
    - HVDC

TABLE III-2
(Continued)

4. Minimizing Power Plant Response Limitations
    - Speed up response
    - Increase maximum output

5. Improvements in System Control
    - On-line security analysis
    - Additional monitoring and control

TABLE III-3

Criteria for Selecting Two Systems to be Studied

1. The selected candidates should be in separate regions of the country in order to acquire a diverse view of the problems.

2. The two candidates should be able to supply the data and specific information necessary for the analysis.

3. The candidates must be willing to participate and cooperative in supplying input.

4. One candidate should be a non-integrated system and one should be a member of a tight coordinating council or power pool.

5. At least one of the candidates should have prior experience with cogenerators and qualified facilities. This experience should be as extensive as possible.

3. Procedures Used in Meetings with Utilities

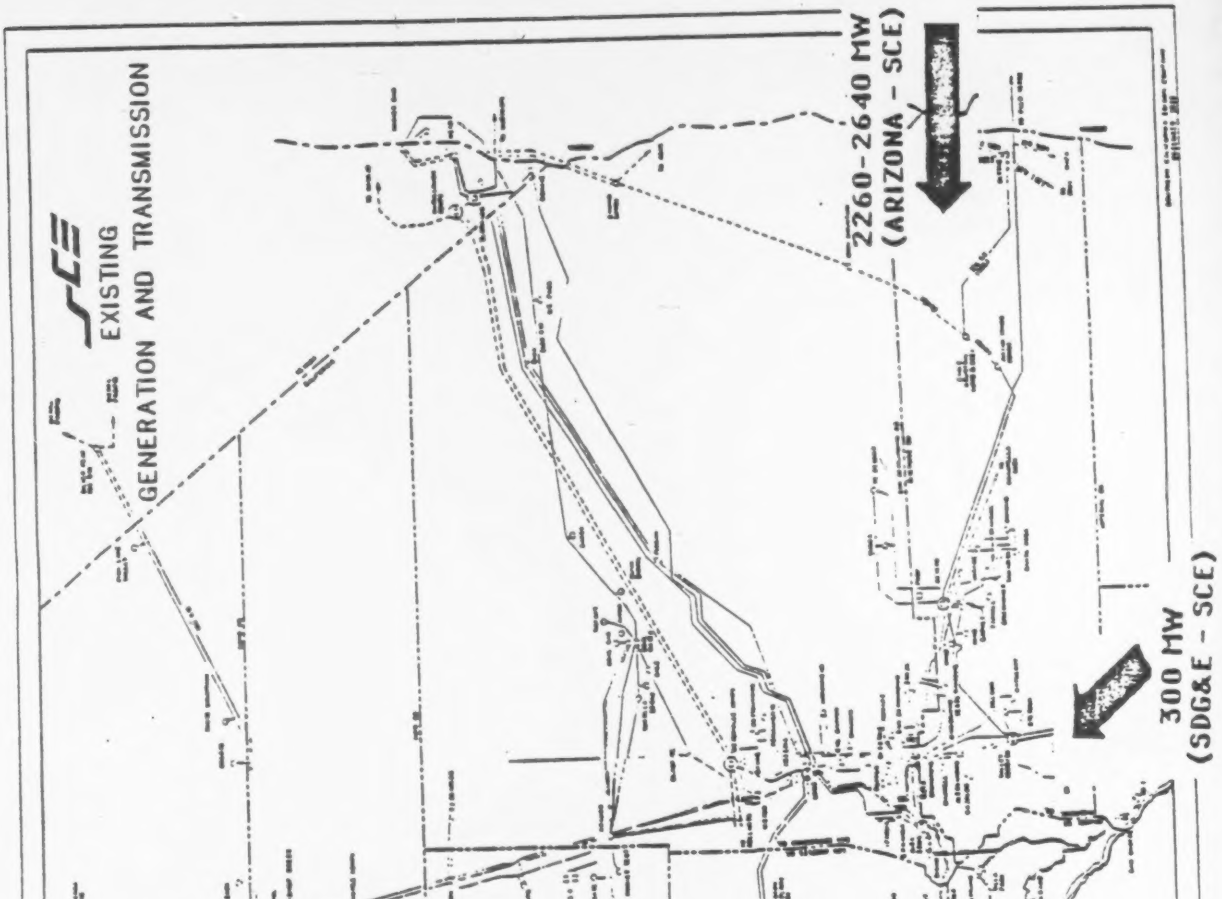
In making the case studies, meetings were held with key representatives of the utilities. Discussions at these meetings were based on an open-minded and constructive approach to making the various deregulation scenarios workable while maintaining the present standards of reliability and the expected level of coordination benefits. The procedural changes to achieve these goals are summarized in the subsequent sections of this report.

During the discussions, every attempt was made to review the reasons behind the views and conclusions of the representatives of the systems involved in the case studies. While this report is the responsibility of its authors, the specific material included and many of the conclusions reached were, in large measure, those of the members of the utility systems that were analyzed.

C. The SCE System and Transmission Constraints

The SCE system supplies an area covering about 50,000 square miles with a population of about 10,000,000 (See Figure III-1). In 1987, it had a peak load of 14,775 MW and supplied 65 million MWhrs of energy to its customers. SCE supplies about 3% of the electric energy consumed in the U.S.

Figure III-1 also shows the SCE transmission network and the key transmission lines involved in the import of power into and the export of power from the SCE control area. The 1986 limitations on imports to SCE are shown on the diagram.

SCE
EXISTING
GENERATION AND TRANSMISSION
2260-2640 MW
(ARIZONA - SCE)
300 MW
(SDG&E - SCE)
4350 MW
(LADWP - SCE)
2000-3000 MW
(PG&E - SCE)
PACIFIC
LEGEND
N

It should be pointed out that these are non-simultaneous limits, and that imports across one limiting corridor affect the limits across other limiting corridors.

The Southern California Edison Company (SCE) is a member of the Western Systems Coordinating Council (WSCC). Hydroelectric generation from the Pacific Northwest plays an important role in the energy supply picture in the Pacific Southwest. The primary reliability-related concern in the West is a disruption of the Pacific North-South Intertie. Loss of both 500-kV alternating current (AC) lines or of both poles of the high-voltage direct-current (HVDC) line will result in serious bulk power supply problems within WSCC. These contingencies will adversely affect the SCE service area by requiring the use of higher-cost energy, or under severe conditions, temporary load curtailments.

The NERC 1986 Reliability Review shows that over 31% of the planned WSCC capacity additions between 1986 and 1995 will be non-utility generators.[1] The size and location of these non-utility generators will be closely watched by the utilities within WSCC to ensure that the transmission system is capable of handling this diverse capacity source. The California-Southern Nevada area is predicting the highest growth in non-utility generation. A primary concern in this area is that, in most cases, the utility has no control over non-utility generation operations. The utilities are required to absorb the energy into their system whenever it is delivered by the non-utility generators. This requirement further complicates the overall operation and planning of the bulk power system in the WSCC.

Over the 1987-1996 time frame, the WSCC has several transmission projects, planned, or in progress, to alleviate its current transmission constraints. These are discussed in Section IV of this report.

D. Description of the PJM System and Transmission Constraints

The Pennsylvania-New Jersey-Maryland Interconnection (PJM) is a power pool consisting of eight utilities serving all or most of New Jersey, Pennsylvania, Maryland, Delaware, and the District of Columbia. All generation is centrally controlled for economy and reliability. In 1986, PJM members served over 8,300,000 customers and a population of 21 million people over an area of 48,700 square miles, and sold 186 million MWhrs of electricity. The 1987 summer peak load was 40,526 MW and the installed capability was 49,489 MW. A map of the PJM system and its major transmission facilities is shown in Figure III-2.

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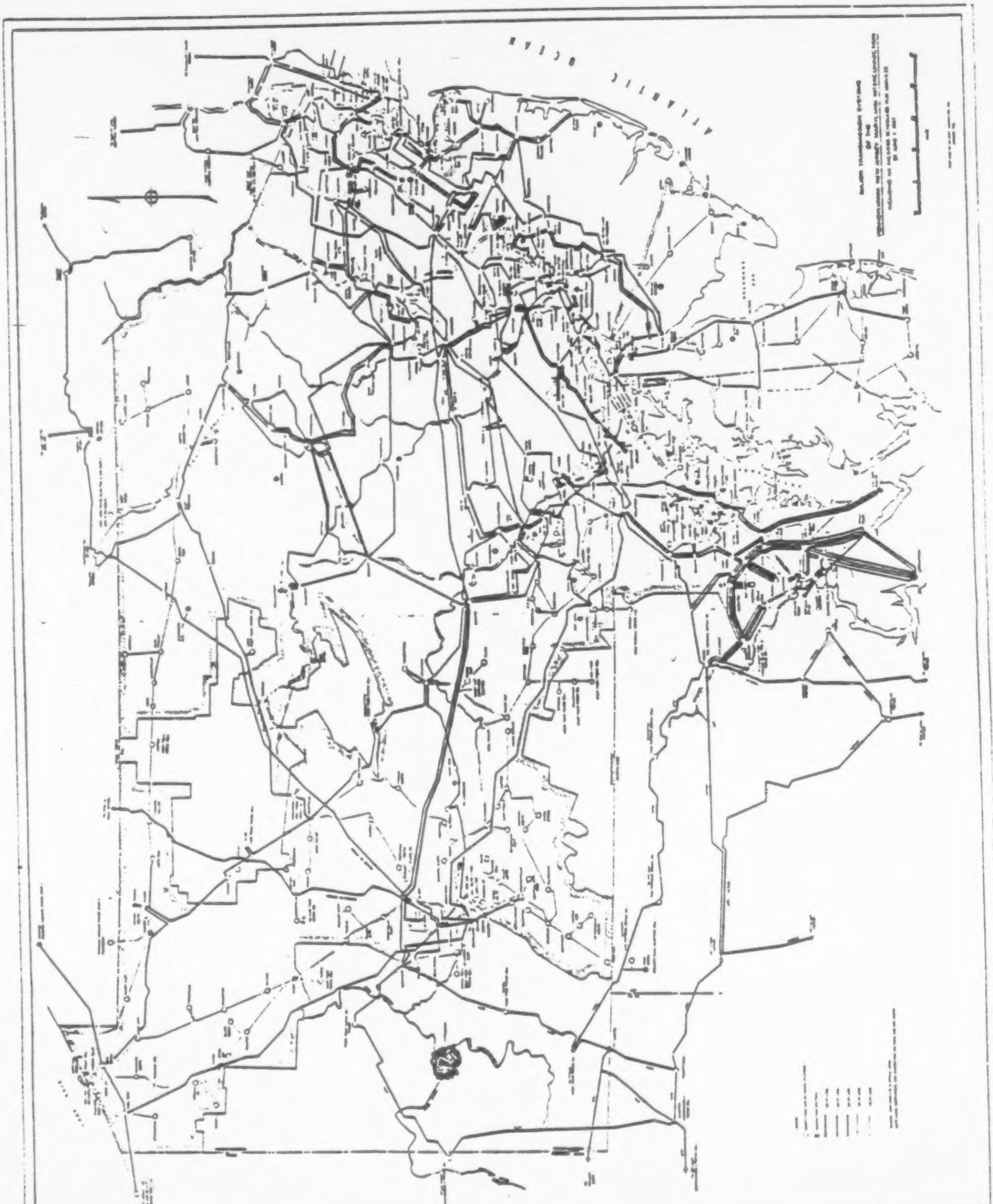
[1] NERC, 1986 Reliability Review; Table 7, Pg. 15.

The members of PJM own generation resources using nuclear, coal, oil, and gas fuel as well as other energy sources including a moderate amount of hydro power. The resources in the eastern part of the area contain a larger amount of oil and gas fueled units. Also, all members own shares of coal-fired units located in the western part.

The members of PJM are connected with each other and with outside pools by a transmission system composed of lines at 500 kV, 230 kV, and various lower voltages. There are ties at 500 kV, 345 kV, and lower voltages with all the neighboring pools: the New York State Power Pool, the East Central Area Reliability Coordination Agreement (ECAR), and the Virginia-Carolina Pool (VACAR), a part of the Southeastern Electric Reliability Council (SERC).

PJM operates on a poolwide central economic dispatch basis to meet customer needs from the most economic generation available recognizing established reliability criteria. With this arrangement, the lowest-operating-cost generators available anywhere in the power pool produce power without regard to individual company requirements or individual company ownership of generating facilities. In any given hour, some utilities will generate less than the requirements of their own customers, and some generate more. Therefore, in any hour, some utilities automatically buy power from member utilities and others sell power to member utilities. Similarly, the member companies of PJM, when economical, purchase power from -- or sell power to -- systems outside PJM. Thus, the transmission system operates to move power among utilities such that the most economic combination of generating units is operating at any given time (consistent with reliability requirements) and the minimum fuel or operating cost is incurred by the utilities -- and their customers-- in aggregate. The savings that result from such pool-wide optimization of generator loading -- that is, the difference between what it would have cost each utility to generate all of its own customers' power requirements and the actual pool



ATLANTIC OCEAN

FIGURE III-2
PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION

costs under the optimum arrangement described previously -- are split equally between buying and selling utilities and with the New York Power Pool and other pools. These savings are reflected in each of the utilities' customer rates.

Since the poolwide central economic dispatch results in the lowest possible total energy cost to the members of the pool, this method maximizes the savings achievable in the market; the transfer of more or less power among the members would be less than optimal and would result in increased overall fuel costs for the power pool. Power transactions between individual PJM members and utilities which are not members of PJM -- in many cases, utilities several states removed from PJM -- occur in a highly competitive market.

System operation is continuously monitored to maintain reliability while operating to achieve economic efficiency. The objective of PJM is to operate in such a manner as to achieve the lowest possible costs while maintaining the highest practical degree of service reliability to the customer loads of the member systems. To meet this objective, PJM operates the system on a single-contingency basis, which was described in Section II. Actual power flows on all major facilities are continuously monitored by the PJM operations computer at the PJM Interconnection Office. The loss of each major facility is periodically simulated by the computer and the redistribution of power flow on each of the major facilities is calculated. Impending overloaded facilities are identified and appropriate adjustments are made to internal generation and to imports from outside PJM to prevent an overload from occurring. This philosophy of operation is consistent with the philosophy of planning the bulk power system.

The PJM operations computer constantly interchanges information with the individual members' operations computers. This includes the data needed for economic dispatch, monitoring the transmission system, monitoring operating reserves, scheduling maintenance, and other functions.

The economic dispatch of the PJM generation, in addition to purchases of power by the members from pools to the west, result in heavy flows of power from the west to the east which are or near the capability of the transmission system. One transmission-related concern of PJM, both regarding operation and planning, is therefore to maximize the amount of economic power, within reliability constraints, that can be transmitted from the western part of PJM and from non-PJM utilities west of the pool to the eastern load centers.

During 1987, the PJM system was loaded to the limit of its capability to transfer energy west to east across PJM 96.8% of the time. The limiting flows are the result of:

- economic purchases from utilities west of PJM;
- internal PJM economy transactions;
- unscheduled flows through the PJM system resulting from transactions by other pools. An example of this is circulating power flows which result from the transfer of energy from Ontario to New York State.

However, analyses conducted in 1984 and 1985 by ECAR-MAAC for DOE showed that the existing transmission system provided an estimated 90% of the economic benefits compared to what could be realized if the existing transfer capability were doubled.

IV. SOUTHERN CALIFORNIA EDISON CASE STUDY

A. Means of Increasing Transmission Capability

The Pacific Northwest and the Arizona-New Mexico region are the Southern California Edison (SCE) Company's major sources of economical power imports. SCE's efforts to increase its import capacity mostly concern the paths from these two areas. They generally involve cooperative studies and actions by various members of the Western Systems Coordinating Council (WSCC), which includes all the major utilities in the western states. Recent steps to increase the total intertie capability have included:

- Upgrading the transfer capability of the Northwest to California 500 kV AC Pacific Intertie from 2,800 MW to 3,200 MW in 1987.
- Increasing the Arizona-California transfer capability to 5,540-5,700 MW from its current 4,900 MW in 1987.
- Completion of the 1,920 MW Intermountain Power Project in Utah and the associated ±500 kV DC line to California in 1987.

Steps being planned for the future include:

- Completion of the DC Terminal Expansion Project in 1989 which will upgrade the Celilo-Sylmar ±500 kV DC line terminal from 2,000 MW to 3,100 MW.
- Completion of the third Northwest to California 500 kV AC Pacific Intertie in 1991, which will increase the Northwest to California AC transfer capability from 3,200 MW to 4,800 MW.
- The addition of phase shifting transformers in southwestern Colorado in 1988 to partially control the loop flow problem the WSCC has been experiencing.
- Addition of a second Devers-Palo Verde 500-kV transmission line which will increase the Arizona-California transfer capability by 1,200 MW.

Table IV-1 presents data showing the large costs of providing these increases in transmission capacity. Obviously, the systems who have made these investments are reluctant to see these facilities used by others without appropriate compensation.

In the past, SCE and the other WSCC systems have utilized almost all of the methods outlined in Table III-2 to increase transmission capability of individual circuits, overcome system related limitations, and reduce transient and dynamic stability limitations. Fast valving, variable series capacitors, braking resistors, load switching, and dynamic system stabilizers on AC systems and HVDC systems have all been pioneered in the U.S. by WSCC systems and have involved SCE. Operation using corrective technology to limit overloads when abnormal contingencies occur have been frequently used by SCE. Appendices B, C, D, E, and F provide five specific examples of methods used to increase transmission capability.

New technologies being considered for future application include controlling the loading of AC lines during normal and emergency conditions by using more phase shifting transformers and solid state phase shifters; rapid adjustment of network impedance; use of static var compensators (SVC); and the use of "NGH" devices to permit increasing series compensation without causing subsynchronous resonance.

B. Problems with Transmission Access and Wheeling

SCE presented a number of specific illustrations showing the effect of additional transmission access and wheeling of power by non-utility generators and by other utilities.

- A large industrial cogenerator is located near a SCE hydro station, both of them connected to the SCE system through two transmission lines. The cogenerator takes his unit off-line, at a time when SCE takes one of the lines out of service for maintenance. The cogenerator comes back on line without warning. The remaining line is overloaded, and SCE must curtail its economic hydro generation to eliminate the overload, increasing its costs.

- In planning generation resources, SCE has had many cogenerators coming on the system with insufficient warning, resulting in excess resources and extra costs to consumers. SCE is concerned that cogenerators could similarly shut down without notice, resulting in capacity shortages. This

TABLE IV-1

SUMMARY OF COSTS AND BENEFITS
TECHNICAL MEANS USED BY SCE
FOR INCREASING TRANSMISSION CAPABILITY

STEP	COSTS	INCREASE IN TRANSFER LIMIT	COST/MW of INCREASE
Increase AZ-CA transfer capability	$232,000,000	1200 MW	$193,000 /MW
DC Terminal Expansion Project	$163,000,000	1100 MW	$148,000 /MW
Third NW-CA 500-kV Pacific Intertie	$534,000,000	1600 MW	$334,000 /MW
Phase shifting transformers in Colorado	$45,000,000	200 MW*	$225,000 /MW

* Phase shifters will reduce transfer capability but will also block loop flow. The net result is an increase in scheduling capability.

could have any adverse effect on their ability to meet future consumer needs.

- There are now situations in which, as a result of loop flows on the WSCC system, SCE has to curtail its participation in the Four Corners plant in order to prevent overloading a transformer there. With more participants and more deliveries made through the WSCC, these situations would become more frequent and more severe, again increasing costs to consumers.

- A customer connected to the distribution system generates DC photovoltaic power which is converted to AC through an inverter. Inverters can reduce the line voltage, and generate harmonics (alter the AC wave shape), which can cause TV and radio interference and overheat appliance motors in other customers' houses, and may also cause misoperation of SCE's protective and control devices, reducing reliability and increasing costs.

- A cogenerator in an industrial park serves most of the other customers in the park, while the others receive service from SCE. All share a distribution system in the park. SCE has sized its transformers and distribution circuit to the park to serve the SCE customers, not the whole park. If the cogenerator's unit fails, the entire load will be drawn from SCE's substation, resulting in an overload which will trip the line, cutting off service to the SCE customers and the cogenerator's customers as well.

- A large induction generator (typical of NUG equipment) is connected to a 33 kV distribution line. If this line should be disconnected from the system, overvoltages as high as 500 volts could occur on the 120 volt outlets of the customers left on the line. This would damage apparatus and appliances and could endanger the safety of customers.

- Wind generators also use induction generators, and involve risks similar to those mentioned above. In addition, the output can change rapidly from nothing to large amounts. On one windless day, SCE took one of two lines out of service for maintenance. These lines served, among others, an industrial customer with wind generation. Later that morning, the wind increased and the remaining line became overloaded. This resulted in an interruption of service to an SCE industrial customer, causing economic losses.

Many of these problems are not impossible to solve technically. However, their solution is often difficult and will impose operating burdens and increase costs to SCE and the consumers it serves. It will require the active and knowledgeable cooperation of the operators of non-utility generators, as well as, in many cases, special controls, communications equipment, and switchgear to prevent malfunctions, overloads, and accidents. The availability of such skilled personnel is extremely doubtful if a large number of NUGs develop in the future. Contracts with non-utility generators should provide for the necessary equipment to be installed so that SCE will have direct control of the NUG generator units if a large amount of such capacity is added to the system. Regulatory provisions did not permit SCE to require the NUGs in these cases to provide the needed controls and operating procedures to avoid these problems before they occurred.

C. Implementation of Deregulation Scenarios

Each of the five contemplated deregulation scenarios requires certain changes in SCE and WSCC procedures, and in the SCE system, so that it may be implemented in accordance with the "ground rules" assumed for these studies, which are:

1. no decline in reliability of service to the ultimate customer;
2. keeping all the benefits which are presently derived from interutility coordination and interchange of economy power; while
3. providing for the changes in the overall system dispatch and in the type, size, and location of generators from the way they would be under the present regulatory rules (If there were not changes in these, then the changed regulatory scenario would not change the overall operating and production economy).

In this section, the changes required to implement each scenario are presented as they were developed by SCE in discussions with the investigators. They are divided into regulatory and legislative changes, procedural changes affecting either the operation or the planning of the system, and technical changes involving changes in physical equipment requirements.

In examining the various scenarios, it was pointed out that only those changes in procedures that result in a change in the physical generation pattern - how much power is produced where - can possibly affect the overall economic efficiency of the system as a whole. Any change that does not alter the physical generation pattern does not change the amount of fuel used, the loadings on transmission lines, the losses, or anything else of a physical nature; any changes in payments, costs, etc., that would result would therefore only represent a redistribution of the previous costs and benefits; such a redistribution may be considered good, bad, or indifferent, depending on one's point of view. They will have no immediate effect on overall economic efficiency. This is not to say that there are no other effects from such transactions. They may indeed have desirable or undesirable long-run socio-economic results and they may affect the incentives various future suppliers receive.

Scenario 1 - Status Quo Plus Rolling Prudency Reviews

In brief (a more detailed description is shown in Section III), this scenario consists of maintaining the present situation, except that "rolling prudency reviews" are instituted.

1. *Regulatory and Legislative Changes*

No basic changes would be contemplated in present regulatory procedures including PURPA or its implementation. Some modifications of present PURPA procedures would be required to eliminate unrealistic evaluations of avoided costs which represent subsidies at the expense of the ratepayers.

The establishment of rolling prudency reviews may require legislative changes, however, to provide more frequent reviews and approvals of project progress by the regulatory commission. This will help to ensure that a decision of a present commission (particularly the inclusion in the rate base of expenditures which had been approved under the rolling prudency review process) will be binding on future commissions.

2. *Procedural Changes - Operating*

Under this scenario, no system operating changes from present practices are contemplated.

3. *Procedural Changes - Planning*

The institution of rolling prudency reviews would require periodic reviews of the utility's plans, its latest revised requirements, and the status of its major projects with the regulatory commission. Except for this addition, SCE's planning procedures would remain substantially as they are at present.

4. *System Changes*

No substantial system changes are seen to be needed under this scenario.

Scenario 2 - Expanding Transmission Access in the Existing Institutional Structure

In this scenario, transmission access is expanded to QFs and IPPs to sell to utilities and to certain large retail customers, so that some "customer shopping" is possible. IPPs and QFs are assured a market under the states' implementation of PURPA.

1. *Regulatory and Legislative Changes*

In order to implement this scenario effectively, SCE requires flexibility in establishing its rates so that it may compete for the load of large customers who are contemplating obtaining their electricity from other suppliers. Without such flexibility, many customers could be lost to NUGs, with a consequent increase in cost to the remaining SCE customers.

The requirements for implementing the scenario depend to a great deal on the actual amount of qualifying facilities (QFs), independent power producers (IPPs), and large customers involved in power transactions, compared to the overall actual size of the system.

2. *Procedural Changes - Operation*

In order to maintain the reliability of the system, the responsible utility must monitor power flows and adjust generation in various locations so that the "first-contingency" criterion is observed. SCE must also have the ability and authority to control all generation regardless of its ownership. This control is required, both under normal conditions and in emergencies, to maintain system reliability and economy.

a. Information Required by SCE

To operate reliably and economically, SCE will require detailed advance information concerning operations and requirements of IPPs, QFs, and large customers. Specifically, QFs, IPPs and large customers would have to provide their hourly load and generation schedules to SCE one or two days in advance. IPPs and QFs would have to provide projected generating costs on an hourly basis. Also, QFs and IPPs would have to keep SCE informed of any changes in the capacity of their units as soon as they are aware of them. This necessitates communications with the QFs, IPPs, and large customers who may be transacting power with outside suppliers.

b. Determination of Generation and Transmission Adequacy

Based on this advance information and as part of its operations planning, the utility will determine which units should be run, which units should provide spinning reserve, and which units should provide regulating reserve. They will also check the loading conditions on the transmission system for various contingencies, as well as for various other scheduled transfers. This check will involve review of voltage and reactive conditions to make sure that reactive capacity is adequate, to maintain good voltage at heavy load, and what steps are needed so as not to produce excessive voltages at light load. The utility will also investigate proposed maintenance schedules as well as ensuring that sufficient capacity is available on the system at all times to meet area control requirements including tie-line and frequency controls.

c. Ability to Perform Incremental Cost Dispatch

Maximum economy in system operation is obtained if all generator units operating at any particular time are operating at the same incremental costs. Dispatch should also be scheduled among the various thermal units so as to make maximum use of available hydroelectric energy. The necessary incremental production cost data will be available from the Southern California Edison units. Such incremental production cost data is also required from the various IPP and QF units if overall optimum system scheduling is to be achieved. If such information is not available from the IPPs and QFs, but rather only the price of electricity to Southern California Edison is available, incremental cost dispatch based on this information would not necessarily minimize total fuel costs on the system.

We conclude that maximum economic efficiency requires true systemwide incremental cost dispatch and that this efficiency cannot be achieved unless the IPPs and QFs provide incremental cost dispatch data to SCE.

Similarly, when generation is adjusted, up in one place and down in another in order to change transmission system loadings to meet safe transmission limitations, there are usually a number of choices of where to make these changes, but only one of these is optimal in that it causes the least increase in total fuel costs. If this optimal choice could not be carried out because, for example, it requires reducing the output of a generator that is not under the control of the utility, then the utility and its customers would be paying an additional cost penalty to protect a transmission system which they share with the independent producer.

d. Complexity of System Control

The addition of a large number of small power producers to the system would greatly increase the number of individual generating sources that must be controlled by the utility. The complexity of operation increases geometrically with the number of points to be controlled, and the difficulty of operating the system would increase dramatically.

There is a limit to the number of generators and wheeling transactions that can effectively be handled from a single control center. If these increase significantly, more control centers would be needed, and the hardware and software of each would have to be more complex. Even with such a costly expansion of the control system, it is questionable whether the system reliability could be maintained because there is no experience available in the control of a system with an explosive growth in the number of small sources.

The problem of increasing system complexity can be illustrated by an analogy to the traffic control at an airport, and the problems that would come from replacing large airliners by small private planes carrying the same total number of passengers.

The suggestion was made that in order to limit the number of players to a practical number, transmission access should be limited to producers that meet some minimum size requirement, such as perhaps 10 MW.

e. Remedial and Emergency Procedures

Where transactions by QFs, IPPs, and large customers could cause safe transmission limitations to be exceeded, it may be necessary for SCE to change QF and IPP generation outputs on short notice. Direct control of the QF and IPP is required to achieve this if appreciable amounts of such generation exist.

It is also important during system restoration after a major interruption that the utility have direct control of all IPPs and QFs. With such control restoration of service could severely hampered, personnel safety jeopardized and risks of damage to equipment increased. The need for such direct control will increase as the number of NUG generators increase.

f. Contract Requirements with NUGS

As part of the implementation of the utility's control authority, the NUG should be required to:

- Provide telemetering, controls, and voice communication;

- Provide necessary advance warning of changes in future operation;
- Provide incremental energy production cost information to the utility;
- Employ qualified operators and maintenance personnel;
- Permit the utility to directly control operation of the unit, including disconnecting the unit if reliability requires it;
- Install and set relaying and protection schemes in accordance with the utility's specifications; permit the utility to test them as required. This includes underfrequency relays to protect the NUG unit, whose settings should be compatible with the utility's load shedding program.

3. *Procedural Changes - Planning*

a. Advance Notification Required

Because of the long lead times needed to build generation and transmission facilities, the planning of a utility's generation and transmission requires adequate advance knowledge of the plans of other providers of generation and of any of their large customers who may wish to obtain their power from outside sources. Therefore, advance notification in the order of at least three to five years would be required for QF and IPP installations, and for large customers who intend to change to another supplier or to return to the SCE system.

The notification must include adequate technical details, including the projected capacity and energy to be supplied, and scheduled service dates. Contractual provisions should define the conditions under which changes in service dates would be allowed and the penalties for non-compliance.

b. Provision of Adequate Generation and Transmission Capacity

Without such notification, alternate generating facilities will be under construction and sufficient time to add the necessary transmission facilities will not be available. The NUGs would have no capacity value and firm transmission service usually could not be offered in such a situation.

Also, SCE would have to increase its generation and transmission reserves (build facilities not otherwise needed) in order to maintain acceptable service reliability in the face of greater uncertainties in load projections and greater uncertainties in future wheeling requirements. In addition, where the required additional generating capacity is expected to be provided by a NUG, uncertainties exist concerning both the completion date for the project and the future availability of the additional generation. This uncertainty will also increase required generation reserves.

c. Impact on Operation of Pool and Reliability Council

While a relatively small number of NUGs will not significantly affect the functioning of SCE, the California Power Pool, or WSCC, the situation will change as the percentage of generating capacity provided by non-utility generators increases. It is essential for the maintenance of reliability that all generators comply with the operating criteria and control and design guidelines of WSCC.

This raises the question as to whether the owners of NUGS should become participants in activities of pools and reliability councils. Their role could have adverse effects on the functioning of these organizations. The owners of the NUGs will be primarily concerned with the optimization of their earnings from their own facilities. The utilities, however, have a larger viewpoint and are concerned with the overall functioning of the system. Having the NUG owners participate in the deliberations and decision-making of the pools and reliability councils could therefore lead to a change in focus from the optimization of the entire system to optimization of individual profits. This would have a serious deleterious effect on system reliability and overall system costs.

4. *Technical Changes - Planning*

Depending on the nature, amount, and location of potential QFs, IPPs, and large customers "shopping" for power supplies, the utility may need to make some of the following technical changes:

- add transmission facilities to provide for greater uncertainties;

- install special devices for reducing the QF or IPP generation very quickly if certain contingencies occur;
- add devices (remote control of circuit breakers, phase shifters, etc.) to control individual circuit loading under various conditions and contingencies, or
- provide extra generating capacity to maintain quality of service under greater uncertainty.

Scenario 3 - All Source Competitive Bidding for New Generation with Mandatory Wheeling

The essence of Scenario 3 is that competitive bidding is required for all new utility generation. Utilities may participate in the bidding both to serve their own loads and those of other utilities, with transmission access as a condition for this participation. Unlike Scenario 2, this scenario does not provide for supplier shopping by customers.

1. *Regulatory and Legislative Changes*

Regulations promulgating procedures to evaluate competitive bids for potential new generation will be required. It is anticipated that the all-source competition for providing generation will be based initially on the utilities' determination of how much base load, intermediate, and peaking capacity is required, and when. Because different types of generation generally involve different lead times for construction, the competition for different types of capacity should be timed according to these lead times. Another factor in determining the timing of the all-source competition should reflect the fact that the process of state participation and approval of the decisions involved will normally require additional time, increasing lead times.

The requirement for mandatory wheeling does not presently exist and can only be implemented through legislative or regulatory changes.

2. *Procedural Changes - Operation*

The same changes in operations procedures as were discussed for Scenario 2, apply to this scenario also.

3. *Procedural Changes - Planning*

The procedural changes in the planning process which were indicated for Scenario 2 also apply to this scenario, with the exception to those referring to large customers, whose right to change suppliers is not included in this scenario. Because lead times are greater, however, uncertainties in future requirements and costs will also increase. This will increase the required generation reserves. As in Scenario 2, uncertainties will continue to exist concerning the service dates for the NUGs that are selected and the future availability of these generator units.

Difficulty will also be experienced in determining the optimum amounts of base load, intermediate and peaking capacity to be added to the system because the optimum mix of generating types depends on the cost and performance differentials which will not be known until bids have been received.

4. *Technical Changes*

The technical changes associated with Scenario 3 are expected to be the same as those listed for Scenario 2.

Scenario 4 - Generation Segregated From Transmission and Distribution Services

In brief, this scenario calls for separation of the generation function of utilities into separate deregulated companies, with transmission and distribution companies remaining regulated. The distribution companies would be responsible for securing power supplies from competing suppliers. Generation and transmission companies could sell directly to large customers.

1. *Regulatory and Legislative Changes*

For this scenario, the transmission company (or transmission/distribution company) would be responsible for the reliable delivery of power from the generation companies. This means that it must have the authority to adjust the scheduling and dispatching of generation in order to maintain reliability of service in the face of existing conditions and possible contingencies. Legal or regulatory procedures to establish this authority are needed.

The deregulation of generation and the separation of integrated utilities into generation and transmission/distribution companies, would also involve extensive regulatory and legislative changes.

2. *Procedural Changes - Operation*

a. Responsibility for Control and Scheduling

For this scenario, it was considered evident that the transmission company (henceforth referred to as TRANSCO), in order to carry out its responsibility for the secure operation of the transmission system, would have to ensure that the totality of the power transaction schedules developed by the generation and distribution companies do not result in power flows which conflict with the limitations of the transmission system. It would, in effect, inherit the basic system control responsibility formerly held by SCE as an integrated utility. As a result, TRANSCO will need to have the right, and the tools, to adjust these proposed schedules and actual deliveries when necessary in order to maintain service reliability and to assign control functions to specific generation units. This authority should be specifically defined as part of all contracts between TRANSCO on one hand, and generation and distribution companies on the other, in accordance with legal or regulatory requirements.

b. Information Required by TRANSCO

In order to perform its function of controlling power flows for system reliability, TRANSCO will need all the scheduling information required from generators, as explicitly listed for Scenario 2: hourly generation schedules, and the state and capacity of all generating sources.

c. Determination of Generation and Transmission Adequacy

TRANSCO, as the single central authority available, would have to determine whether the generation and transmission systems can reliably serve actual and projected loads using the schedule generation. Specifically, they would have to ensure the availability of adequate spinning reserves, other operating reserves, and regulating capacity. Also, they would need to monitor the transmission system and determine whether it is capable of carrying present and future loadings including provision for possible contingencies.

d. Tie Line and Frequency Control

TRANSCO would need to arrange at all times for the control of the system, including in particular, for Automatic Generation Control (AGC). This can only be done by assigning to a large number of generating units the task of increasing or decreasing their output to match the constant rise and fall of customer loads and occasional changes in generation output, and to adjust output as needed to maintain the system frequency at a constant 60 Hertz. Participation in this regulating duty reduces a unit's fuel efficiency and tends to increase its maintenance requirements; so that generation companies can be expected to participate in area control only to the extent that they are required to by contractual arrangements, and to the extent that their participation is verified by TRANSCO.

e. Ability to Perform Economic Dispatch

In order to maintain the benefits of economic dispatch based on incremental costs as a means of minimizing overall generation costs, TRANSCO would need contractual agreement of its suppliers to operate under such a system. The TRANSCO would have to have communications with each of its supplying generation companies to notify them of the required generation. The generation company would have to supply its incremental cost data to TRANSCO. This implies a complex and frequently changing data communications system.

If, as seems likely, agreements with suppliers providing for economic dispatch by TRANSCO may not be feasible, a considerable loss of economic efficiency would result.

f. Remedial and Emergency Procedures

System restoration in the case of a full or partial system collapse will involve particular difficulty as responsibility for generation is scattered among a large number of independent parties. The time required to restore service, the possibility of a new collapse in the course of restoration, and the danger to personnel and equipment, will worsen to the extent that a common control of the transmission and generation systems is diffused. Direct control by TRANSCO is therefore essential.

If TRANSCO found threats, present or future, to system reliability based on its evaluation of system adequacy, TRANSCO would need the authority to determine the best remedial measures, and to carry them out. The latter would include reducing or increasing generation of specific units, including starting up units not in operation, to provide the necessary operating reserves and to adjust transmission loadings.

The arrangements for prompt or immediate action when a TRANSCO is supplied by a number of individual generation companies, and when these in turn may be dealing with several transmission companies are particularly difficult, and may in practice be unworkable.

One of the last extreme measures in preventing an imminent system collapse, or in reducing its extent, is to shed load, that is, to deliberately interrupt service to some customers, selected with a view to potential effects of interruptions and to geographical dispersion. This is generally done with pre-planned automatic control action. TRANSCO needs the authority and physical means to shed loads on an equitable and technically justified basis, without regard to which distribution company serves these loads.

3. *Procedural Changes - Planning*

a. Load Projections and Power Supply Planning

Under this scenario, the distribution company or transmission/distribution company will be responsible for assuring a reliable generation source for its customers. To do so, it will have to obtain advance information on its future loads and make advance arrangements with generation companies in sufficient time to provide for the lead time needed to build these facilities. Adequate methodologies exist for forecasting distribution loads but not for predicting future "customer switching."

It should be the responsibility of this distribution or transmission/distribution company to arrange for different types of generation (base load, intermediate, and peaking). Reasonable lead times for this activity would be:

- ten years for base load generation;
- seven years for intermediate generation;
- four years for peaking; and
- three to ten years (concurrent with the lead times for generating units) for any units whose location would require reinforcements of the transmission system.*

If this schedule is met, and the transmission/distribution company correctly projects its future needs, no increase in generation reserve requirements is theoretically needed. On the other hand, there will be strong incentives for the transmission/distribution company to underforecast long-range needs. This would keep their advance financial commitments to a minimum and avoid risk of future excess capacity. It will, however, result in excess amounts of short lead capacity being installed at considerable economic penalty or a decline in reliability.

Present utility practice in generation planning is to require a diversity of fuel types, to avoid excessive dependency on one type of fuel whose sources may be interrupted, or whose use may be limited by environmental or other situations. Scenario 4 provides no defense against this. If one fuel should become cheaper than others in a region for a long period, such as a decade, there would be a strong tendency for all the generation companies to build generation using this same fuel, and no one entity responsible to prevent it. National dependence on oil and gas would undoubtedly increase because of the lower capital costs of plants burning such fuels.

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*. NERC reports show a range of lead times for the planning, siting, and construction of transmission lines of three to ten years, with an average of 5 years.

b. Transmission Planning

It will be the responsibility of both generation and distribution companies to make arrangements with TRANSCO to deliver the power from generation to distribution. TRANSCO will require adequate notice of these requirements so that any necessary facilities can be built. This notice requirement corresponds to the notice of three to ten years referred to in Section 3a above. Lacking adequate notice, TRANSCO would be limited to in transmitting the power on an as-available, or interruptible, basis only.

TRANSCO would plan the expansion of its transmission lines and substations in accordance with present planning techniques, but based on the requirements defined by generation and distribution companies. This would include providing transmission for contracted services, that is, building a transmission system capable of carrying out contracted transactions under reasonable contingencies, based on reliability standards similar to those in use today. It would also be essential that facilities installed by TRANSCO to meet specific requests of generation and distribution companies be paid for, whether ultimately used or not, i.e., a "take or pay" arrangement. TRANSCO would not be likely to install any facilities for unexpected needs not specifically contracted for by generation and distribution companies.

c. Certainty of Load and Generation Projections

Individual load projections made by distribution companies may be wrong. Generation contracted for by distribution companies may be late coming in service. While these occurrences are not unknown in present utility planning, the responsibility for maintaining service lies with a single organization, the supplying utility.

A distribution company that overestimates future loads will pay for unnecessary commitments. If it underestimates its loads, it may suffer occasional interruptions but more often the effect will be that it will have to purchase the deficient power at a higher cost on some type of "spot market." Either of these cost increases will be reflected in the customers' rates. Increased interruptions would increase consumers' economic penalties.

A generating company may fail to produce the capacity and energy for which they have contracted. If the deficiency is large, in power interruptions will occur. If it is small, power may be available from more costly units in the same generation company, or from other companies. How the additional costs will be borne will depend on the contracts between the generation and distribution companies.

These possible unexpected changes in generation or loads will have an impact on the power transferred by TRANSCO. This could affect the reliability of the transmission system, and TRANSCO may have to order changes in generation at different locations. Any costs should be borne by whichever party is not meeting its contract requirements.

d. Maintaining Reliability and Coordination

It may be noted that in discussing Scenario 4, the ground rules of maintaining existing levels of reliability and inter-utility coordination cannot be met. Lowered reliability will result with this scenario. This will result since there is little expectation that the generation and transmission functions can be separated into organizations with different goals without a loss of coordination. While TRANSCO may build a transmission system that meets present standards for operability under ordinary contingencies, it will be very difficult under this scenario to obtain quick coordinated action under severe contingencies, particularly those more severe than provided for under planning standards. In addition, the diffuse responsibility for planning generation is likely to result in undesirable mixes of generation types and excessive dependence on one type of fuel in a region.

4. *Technical Changes*

The technical changes associated with Scenario 4 will consist of changes in the generation mix toward smaller units and increased dependence on the fuel that is cheapest in the region.

System controls, such as AGC, may become even more complex due to the proliferation of small units which will have to be controlled and participate in area regulation.

Scenario 5 - Common Carrier Transmission Services in a Disaggregated, Market-Oriented Electric Power Industry

This scenario varies from Scenario 4 in that transmission companies are completely separated from distribution companies as well, and are required to provide transmission services as "common carriers."

1. *Regulatory and Legislative Changes*

Scenario 5 would require the same regulatory and legislative changes as Scenario 4 - establishing the control authority of the transmission company, deregulating the generation and disaggregating the utilities - and also provisions to define the responsibilities of transmission companies as "common carriers."

2. *Procedural Changes - Operating*

For this scenario, the operating changes would be the same as for Scenario 4: the transmission company, being responsible for the reliability of the transmission system, needs the authority and the tools to adjust proposed schedules and actual deliveries in order to keep power flows within reliability limits. The definition of the transmission company as a "common carrier" cannot make much of a difference in operation: TRANSCO will handle those transactions that it can without jeopardizing reliability, and presumably not others, with or without this designation.

3. *Procedural Changes - Planning*

The planning changes involved in this scenario depend entirely on whether the term, "common carrier," is interpreted as meaning that the transmission company must stand ready to perform any requested transmission service on short notice, i.e., within less time than that needed to build additional transmission facilities (typically three to ten years), or whether it must only be ready to provide firm transmission upon sufficient notice and subject to a financial commitment (take-or-pay), and transmit power on an as-available basis in the meantime. In the second case, the technical changes are similar to Scenario 4. The following discussion applies to the first case, in which TRANSCO is expected to accommodate any transmission request without previous notice, or perhaps something in between, in which TRANSCO must be ready to accept some short-notice transfers but not to satisfy unusually sudden and large transactions.

The transmission company will have the responsibility for providing transmission capacity to supply any potential consumers from any potential source. This will require studies of all reasonable combinations of source and consumption points. Taken to its logical extreme, this would require a grossly overbuilt and costly transmission system, whose actual utilization would be very low.

4. *Technical Changes*

Additional transmission lines, compared to the requirements of Scenario 4, would be needed to provide common carrier service if the advance notice provided in Scenario 4 would not be provided. Transmission facilities that would make possible a full spectrum of sales between suppliers and purchasers would be needed. This would involve a very major expansion of the transmission system; many of the additional facilities would be under-utilized most of the time.

V. PJM INTERCONNECTION CASE STUDY

A. Means of Increasing Transmission Capacity

The economy of PJM generation is frequently limited by the transmission system's capability to transfer power from west to east while observing their rules of safe operation. Because of these limitations, PJM has taken a number of steps in the past to increase the transmission system's capability, and is considering additional ones. The transmission system's capability to transfer power is usually limited because of a contingency consideration: the fact that if one line were to be suddenly tripped out, another line would be thermally overloaded or, more often, subject to excessive voltage drops. Therefore, methods to increase the capability of the system may fall into one of two categories: either to "remove the bottleneck" by increasing the capability of the individual line which would be overloaded during one of the contingencies, or to change the power flows on the system in such a way as to alleviate the limitation with this amount of power transfer. The following are some steps that have been taken in recent years in order to increase transmission system capability:

1. *Control of Individual Line Loadings*

For a given pattern of generation, there are three methods in which transmission limitations can be relieved without actually building new lines or removing lines from service.

- One method is to use phase-shifting transformers ("phase shifters") to change the way the power flow divides along different paths, decreasing the flows that are too high and increasing others that can safely be increased. PJM intends to install two 345-kV phase shifters at Ramapo substation, near the border between New Jersey and New York State, that will control loop flows through the PJM system. (While, in some situations, phase shifters can increase system transmission limits by changing the division of power flows, they are not a universal cure because of their cost, and because control problems can arise if they were applied in many phases. Also, the indiscriminate use of phase shifters to resolve specific problems may give rise to other problems at other locations that are equally severe.

- Another way is to change the impedance of a transmission line. The impedance of a circuit is a basic characteristic of a line depending on its length and configuration. Power flows on parallel paths divide on these paths according to their relative impedances; more power flows on the paths with lower impedance. The impedance of a line can be increased by inserting "series reactors" in them. This was done by Philadelphia Electric Company on the Graceton-Nottingham 230-kV line and by Public Service Electric & Gas Company (PSE&G) on 138 kV circuits in several Northern New Jersey locations (Figure VI-1). Another way of increasing the impedance of a circuit, if it is directly connected ("in series") to a transformer, is to order a specially-designed high impedance transformer. PSE&G has done this in two locations to limit the current through 138-kV cables.

- A third method consists of using special measures in a corrective mode to change power flows after a contingency actually occurs. Special measures are used relatively rarely on the PJM system as compared to SCE and the western systems. Recently, however, when a major transmission line crossing the Delaware River was put out of service for a long time due to being hit by a ship, arrangements were made to trip a generating unit at the Salem nuclear plant if a specific transmission line (Salem-Deans) was lost. The loss of the Salem-Deans circuit, with both generators at Salem operating at full load, would have caused the instability of generation in the eastern PJM area. Classic preventive mode operation would have required reducing the level of output of the Salem or Hope Creek nuclear units for the duration of the outage of the river crossing, and would have caused a much larger economic penalty than the relatively rare tripping of the Salem unit.

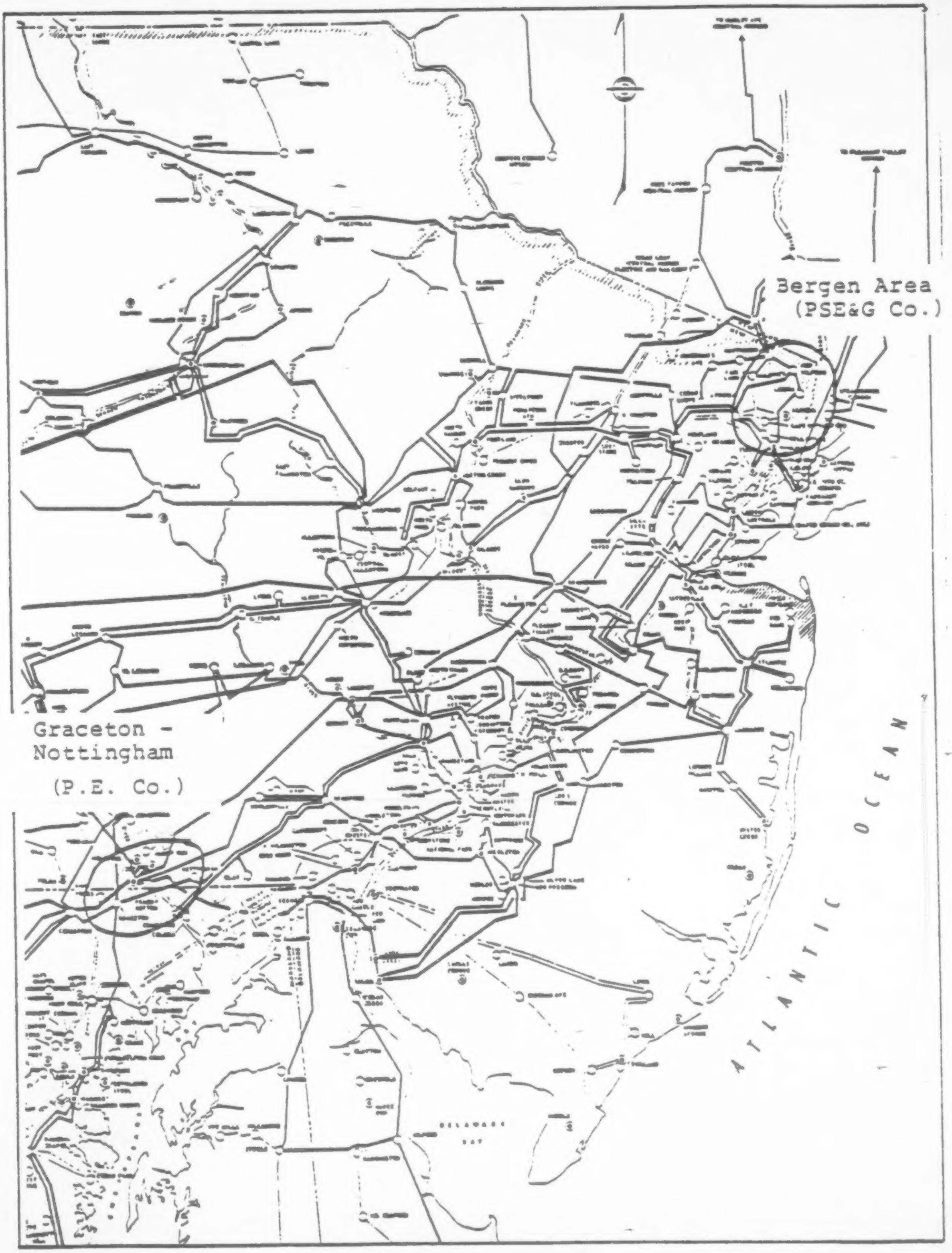
Bergen Area
(PSE&G Co.)
Graceton -
Nottingham
(P.E. Co.)
ATLANTIC OCEAN
DELAWARE BAY

FIGURE V-1
SERIES REACTOR SITES

PJM is very concerned with possible malfunctions of special remedial measures, and particularly with potential unpredictable interactions between them if there are many of these schemes.

- Network rearrangements. Sometimes, opening a transmission circuit is an effective way of reducing transmission limitations. This is particularly true when the loss of a high-voltage line would result in overloading a lower-voltage line. In the summer of 1987, the Hosensack-Buxmont 230-KV line was opened 25 times in order to eliminate the transmission limitation which existed because that line would have been overloaded if the Hosensack-Elroy 500-KV circuit, running approximately parallel to that line, were to trip out. This is an effective step when other transmission routes to the load centers are available.

2. *Increasing Uncontrollable Voltage Decay Limit*

When the PJM transmission system is the limiting factor, 85% of that time the limitation is due to voltage-related factors and 15% of that time it is due to thermal limitations. If the transmission limit is exceeded and certain contingencies (generator, line or transformer outages) occur, the voltage in the receiving part of the system would drop to such an extent that uncontrollable voltage decay would occur. The effectiveness of many reactive power sources would be reduced at the same time that additional reactive power would flow on transmission lines. These increased reactive power flows would in turn cause additional drops in the voltage with the effect that system voltage would collapse. Such sequences of events have happened a number of times in the past, especially on foreign systems. It was the cause of a blackout of a large part of the Tokyo area in 1987. A number of measures were taken in order to alleviate the limits on the PJM transmission system related to uncontrollable voltage decay.

- 2945 MVar of capacitors were installed on the PJM bulk power transmission system.
- Voltage profiles were changed.
- 230-kV lines were upgraded

3. *Increasing Thermal Limits*

Thermal limitation (danger of overheating a component of the transmission system due to excessive current flowing through it) in the case of a contingency is the limiting factor on the transmission system 15% of the time. The following steps have been taken in order to increase the thermal limits of the transmission system:

- Changing ratings with ambient temperatures. The thermal limitations on a component depends on the ambient temperature. In cold weather, a component can safely carry more current before it reaches a given maximum permissible operating temperature, than in hot weather. In the past, components were rated based on the highest ambient temperature which was likely to occur. Typically, three separate ratings might be used for summer, winter, and spring/fall. It has now become possible to make the ratings vary with the actual ambient temperatures by entering the relationship between the ratings and the ambient temperatures, as well as the ambient temperatures, in a dispatch computer. This has permitted increasing the thermal limit of the component whenever the weather is relatively cool.

- Replacing the limiting components. Sometimes the thermal rating of a transmission line or transformer is limited by the thermal limitation of a relatively minor component, such as a wave trap, a metering device, etc. In these cases, the capability of the transmission system was increased at relatively little cost by replacing these minor components.

- Basing thermal ratings on four-hour limits instead of longer-term ratings or continuous limits. Since thermal ratings are based on limiting the heating of a component, and heating is a gradual process, an overloaded component can safely sustain a heavier loading if this loading will only continue for a short time. Therefore, the thermal rating of some components was increased by basing it on the amount of load the component can carry for four hours without overheating. This rating, if used in connection with contingencies, is generally sufficient to permit the system operator to make changes in the generation pattern and thus relieve the overload on the component in the time allotted.

- Re-sagging circuits. On some transmission lines, the thermal limit is determined by the amount of sag in the conductor when the conductor expands as a result of overheating. When the sag is excessive, the conductor may come too close to the ground and create a safety hazard. Some companies have found it possible and cost-effective to increase the thermal rating of some transmission lines by reducing the sag on critical spans. The feasibility of this technique depends on the construction of the tower and the amount of increased tension that is permissible.

- Basing line ratings on higher conductor temperatures. As mentioned earlier, transmission line ratings are generally based on the maximum temperature that a conductor is permitted to reach when carrying the full rating. The higher the temperature, the greater damage can be done to a conductor whenever the rating is reached. Typically, the duration of operation at high temperatures during the lifetime of the line results in annealing of the conductor metal, leading to brittleness and possible shortening of expected conductor life. Since some lines are not expected to operate at high temperatures very often, some companies have increased their thermal rating in such a way as to permit the conductor to reach the relatively high temperature of 160°C without causing an excessive accumulation of annealing. In these cases, the structures were modified to increase the conductor height to permit the increased sag at 160°C.

4. *On-line computer contingency analysis*

The dispatch computers of both the PJM Interconnection and the individual members constantly monitor the actual currents flowing on all transmission lines. Periodically, depending on the capability of the computer, the effect of various contingencies are calculated to determine whether any of the contingencies would lead to overloads or excessive voltage drops if they occurred. The frequent recalculation of these contingencies permits loading the transmission system to the fullest safe limits, instead of having to rely on pre-calculated limitations which must include a substantial safety factor to account for possible variations between actual and expected flows.

B. Problems with Transmission Access and Wheeling

PJM has accommodated the addition of a number of non-utility generators (NUGs), representing a relatively small part of the total generation of the PJM system. Based on their experience with these NUGs, and others that are proposed, PJM expressed a number of concerns about the effects and the costs to utilities and their customers of requiring the utilities to buy power generated by the NUGs, and to wheel power for them. The following are some of the specific concerns expressed:

- Difficulties in keeping the system operating while making reinforcements needed because of the addition of NUG facilities. For example, one typical system reinforcement consists of circuit breaker replacements. Adding generation to the transmission or distribution system increases the short-circuit currents that circuit breakers must be capable of interrupting. These circuit breakers were originally selected based on the utility's generation expansion plans, with the expectation that they would not need replacement throughout their normal expected life. If a NUG is added where no generation had originally been planned, higher short-circuit currents may occur, requiring replacement of the existing circuit breakers. Also, conductors may have to be replaced by larger ones, and other system rearrangements made, to accommodate larger currents resulting from additional, and originally unplanned, generation sources.

- The application of avoided cost pricing as a requirement of the Public Utility Regulatory Policies Act (PURPA) has brought about some unreasonable and uneconomic requirements on the members. In one case, due to peculiarities of the way that avoided costs are calculated, a member is paying more for energy (i.e., without guarantee of availability) than for combined capacity and energy (i.e. with some guarantee of availability). Inconsistency in avoided cost definitions between the different states is expected to make both planning and operation more complex.

- The impact of non-utility generators on the operation and planning of the PJM system is illustrated by a situation in the Northern part of the Pennsylvania Power and Light Company (PL) service territory. A number of new generators proposing to burn culm (anthracite mining waste) have emerged in that area. The culm is considered an environmental hazard and probably a safety hazard also. The transmission tying this area to the rest of PL and PJM was not designed to accommodate the expected amount of NUG generation, some 800 to 1000 MW, in addition to the existing PL generation. Studies indicated that a stability limit would restrict the amount of NUG generation in that area to 465 MW. Even at this level, it will be necessary to limit the output of NUGs under certain conditions and PL generation in the area will have to operate with certain minimum reactive power outputs to maintain stability. This limit on NUG output is a function of load level in northern PL. As load grows, the amount of NUG generation that can be accommodated will increase. As a result of negotiations between PL and prospective NUGs, an understanding has been reached about restrictions on the amount of NUG to be installed, and on operating procedures and financial arrangements to curtail production when conditions on the electric system make it necessary. The Pennsylvania Public Utility Commission was petitioned for a declaratory judgment endorsing this agreement. The Commission found "the terms of the Joint Petition are just, reasonable and in the public interest."

C. Implementation of Deregulation Scenarios

Each of the five contemplated deregulation scenarios requires certain changes in PJM's and individual members' procedures and in the PJM physical system so that it may be implemented in accordance with the "ground rules" assumed for these studies, which are repeated here for convenience:

1. no decline in reliability of service to the ultimate customer;
2. keeping all the benefits which are presently derived from interutility coordination and interchange of economy power; while
3. providing for the changes in the overall system dispatch and in the type, size, and location of generators from the way they would be under the

present regulatory rules (If there were not changes in these, then the changed regulatory scenario would not change the overall operating and production economy).

Again, in this section, the changes required to implement each scenario are presented as they were developed by PJM in discussions with the investigators. They are divided into regulatory and legislative changes, procedural changes affecting either the operation or the planning of the system, and technical changes involving changes in physical equipment requirements.

Scenario 1 - Status Quo Plus Rolling Prudency Reviews

1. *Regulatory and Legislative Changes*

Even though Scenario 1 represents the present regulatory and legal situation, with the exception of the institution of "rolling prudency reviews," there is a need expressed for two changes:

- The institution of "rolling prudency reviews," in itself, appears to need legislative support in binding later utility commissions to accept the decisions of the previous ones. Lacking this, rolling prudency review could not be effective.

- A number of operating requirements (see below) and planning requirements may need regulatory or legislative backing. The petition of PL and NUGs for a declaratory judgment discussed earlier in this section, is a good example of such a need for regulatory backing.

2. *Procedural Changes - Operating*

While present operating practices have been reasonably adequate until now (see concerns in Subsection B above, however), PJM is concerned that problems that can be lived with when there is only a small amount of NUG generation can become major problems as these resources grow proportionally more. Therefore, even under an expanded Scenario 1, in order to maintain the existing benefits of reliability and economic operation, NUGs should be subject to the same operating rules as if they were under utility ownership. Specifically, the PJM member utility to which the NUG is connected should have the authority to do the following for these units:

One to two workdays in advance:

- Schedule unit commitment; and
- Schedule unit output, in accordance with system economic dispatch.

Continuously:

- Schedule spinning and regulating reserves;
- Subject the unit to tie line and frequency control, on the same technical basis as a similar utility-owned unit would be;
- Schedule unit voltage and reactive output;
- Include the unit in a remedial measures program, if needed; and
- Curtail unit output if necessary for transmission reliability.

As part of the implementation of the utility's control authority, the NUG should be required to:

- Provide telemetering, controls, and voice communication;
- Provide necessary advance warning of changes in future operation;
- Provide incremental energy production cost information to the utility;
- Employ qualified operators and maintenance personnel;
- Permit the utility to directly control operation of the unit, including disconnecting the unit if reliability requires it; and
- Install and set relaying and protection schemes in accordance with the utility's specifications and permit the utility to test them as required. This includes underfrequency relays to protect the NUG unit, whose settings should be compatible with the utility's load shedding program.

The implementation of utility control of NUGs may not be necessary to its fullest extent in Scenario 1 as long as NUGs do not form too large a portion of all generation sources. However, signs of their future need are seen in some areas of PJM, as in the case of the culm-fueled NUGs in the northern section of PL. It is important to establish the basic principles early, since otherwise too many of the early NUGs might be exempted from the rule as part of their contracts with the utility.

If these conditions are not met, the consequences would include some or all of the following:

- Loss of service reliability;
- The utility taking up a burden at a cost which should properly be part of the cost of generation; and
- The utility reducing some of its generation which would have cost less than the price it is paying for power purchased from NUGs.

Both reductions in service reliability and unnecessary costs to the utility are eventually reflected in cost and inconvenience to the utility's customers.

Even at present, some PJM utilities report that the implementation of PURPA rules, which require the utilities to buy QF power even when this power costs more than the current incremental cost, is undermining the fundamental ground rules of maintaining reliability and economic benefits.

3. *Procedural Changes - Planning*

The institution of rolling prudency reviews would require periodic reviews of the utility's plans, its latest revised requirements, and the status of its major projects with the regulatory commission. NUGs must notify the host utility of their plans for unit installation and retirement, and for wheeling of power to customers other than the host utility.

Generation reserve requirements may be subject to change as a result of a substantial amount of NUG installations: increasing reserve requirements to make up for the greater uncertainty in loads and generation supplies, both in the near-term and the long-term; decreasing reserve requirements as a result of smaller average unit sizes (a minor effect, quantitatively) and shorter construction lead times.

Utilities may be forced to build smaller units in response to the need for shorter construction lead times. This may cause increased fuel costs since the types of units that can be built quickly are usually those with high, and potentially much higher, fuel costs such as gas- and oil-burning combustion turbines.

Internal PJM planning procedures may have to be modified to reflect the need for including NUG data in pool capacity planning.

4. *Technical Changes*

Depending on the nature, amount, and location of potential NUGs, the utilities may need to make some of the following technical changes:

- Add transmission facilities that would otherwise not be required;
- Install remedial measures for reducing either the NUG or utility generation under various conditions and contingencies;
- Add devices (remote control of circuit breakers, phase shifters, etc.) and expand the functions of the Interconnection Control Computer to control individual circuit loading under various conditions and contingencies, or
- Increase generation reserves to provide equal quality of service under greater uncertainty.

Scenario 2 - Expanding Transmission Access in the Existing Institutional Structure

1. *Regulatory and Legislative Changes*

This scenario carries the possibility that the number of NUGs could become much greater than for Scenario 1, and may result in an unpredictable amount of customer shopping for lower cost suppliers. The changes referred to for Scenario 1, to provide regulatory and legislative backing for operating control of NUG units by the utility, are therefore more urgently needed in this scenario.

2. *Procedural Changes - Operating*

The control of NUG operation by utility operators, described for Scenario 1, to ensure overall system reliability and economy is made more necessary by the potentially larger amount of NUG generation and the potential for substantial customer shopping.

The potential competition between utilities, including members of PJM, for industrial customers raises the strong probability that many forms of cooperation between utilities that have been customary in the past may become weaker or disappear. These forms of cooperation range from the free exchange of information to sending work crews to help another utility which has suffered severe storm damage. Concerning the latter however, some PJM members feel that this practice would remain, because "in times of natural disaster we appear to pull together."

3. *Procedural Changes - Planning*

In addition to the changes indicated for Scenario 1, there would be a need for a PJM procedure, or protocol, to report customers' plans for changing suppliers. Care must be taken to avoid errors of omission or duplication, so that the needed capacity will be provided, but will not be provided twice, by both the present and future host utilities.

In planning as in operation, inter-utility cooperation may become a victim of competition for customers. The exchange of plans to acquire customers from third parties, for example, is most unlikely, as it might endanger the proposed deal. Competition for low-priced energy suppliers would entail similar problems.

4. *Technical Changes*

Assuming larger amounts of NUG generation than with Scenario 1 and a substantial amount of supplier shopping by large customers, the changes described for Scenario 1 would also apply, but on a larger scale.

Scenario 3 - All Source Competitive Bidding for New Generation with Mandatory Wheeling

1. *Regulatory and Legislative Changes*

Legislative or regulatory changes would be needed to define rules to protect all concerned, including utility customers. Such changes are always very complex because they are applied to many different situations, and they often have unexpected results. While these case studies were intended to examine the technological aspects of implementing the five regulatory change scenarios, the technological scenarios are impacted by public interest and public policy considerations, and it is impossible to keep the two types separate. Certain of the following points involve the interface between the technical and non-technical areas, but they were mentioned by the utilities.

- The utility should be responsible for writing detailed design specifications to be used in preparing bids. The utility's service reliability, for which it has full responsibility, will be impacted by a plant's reliability throughout the plant's lifetime; the utility has the experience to know what plant design features are needed to produce reliability in the short and long runs.
- The requirements for capacity and for energy should be specified separately.
- The utility commission should review and approve the utility's specifications. (Not all members of PJM agree that the commission should do this.)
- The utility should be responsible for selecting the best bid. The possibility of negotiating with several of the best bidders should be left available.
- A time limit should be set on opportunities for losing bidders to appeal to the commission. (Some PJM members question whether there should be an appeals process at all.)
- The final contract should be submitted to the commission for approval.
- The approval of the contract by the present commission should be binding on future commissions. This provision should be fixed by appropriate legislation.

2. *Procedural Changes - Operation*

The procedural changes in operation that are called for in Scenarios 1 and 2 also apply to Scenario 3.

The potentially large number of possible bilateral and multilateral arrangements will increase the difficulty of operating the transmission system reliably.

3. *Procedural Changes - Planning*

Experience indicates that PJM members can need as much as eight to ten years' lead time to build a new transmission line; there have been cases, such as the Washington 500-kV loop (see Appendix A) in which much more time has been needed. Therefore firm wheeling requirements of NUGs and supplier-shopping customers must be applied for, and the users' financial responsibility firmly committed, sufficiently in advance of when the wheeling is to be provided, so that if additional facilities are required, the needed system additions can be made. The advance notice required will obviously be much longer for large wheeling requests which will require the addition of new lines.

4. *Technical Changes*

The technical changes associated with Scenario 3 should be substantially the same as for Scenario 2, except that in the absence of supplier shopping by customers the amount of generation reserves needed to provide for load uncertainty would be less.

Scenario 4 - Generation Segregated From Transmission and Distribution Services

1. *Regulatory and Legislative Changes*

For this scenario, legislative or regulatory changes may be necessary to establish the responsibility and authority of individual transmission, or transmission/distribution, companies to provide for the reliability and economic dispatch of the power flowing through the area's transmission. Specific responsibilities and authorities will be discussed with the procedural changes below.

The need for a particularly extensive transmission system would particularly emphasize a problem that already exists now: the difficulty and delays involved in the environmental review process. There is no burden placed on environmental review agencies to approve at least one alternate, nor to produce a final decision within a reasonable time. Each of the proposed scenarios, in sequence, implies greater problems in obtaining approval for constructing the transmission needed to support it.

2. *Procedural Changes - Operation*

It would not be possible to keep the degree of reliability and of production cost savings that are due to PJM's tightly coordinated organization, without integrating the individual transmission/distribution companies into an equally integrated Transmission Pool. This pool would perform essentially those overall regional control functions now performed by the Interconnection Control Center, but it would apply the same operating rules, controls, and requirements to utility members and to NUGs. Control functions over individual units, whether utility-owned or NUG, would be through the members under the same conditions as they are now. All energy purchases would be made by the Pool, but each member would be responsible for providing his own generating capacity resources, from firm contracts, "futures groups" and brokers, and the spot market.

3. *Procedural Changes - Planning*

Each transmission/distribution or distribution company would be individually responsible for assuring its own generation capacity resources. Backup contracts would be needed to provide reserves to back up energy purchases made by the Transmission Pool.

As to transmission planning, the Transmission Pool would have to supervise and coordinate transmission planning by the transmission companies using procedures similar to those used by the PJM Interconnection today.

4. *Technical Changes*

The technical changes associated with Scenario 4 are expected to be essentially the same as those associated with Scenario 3.

Scenario 5 - Common Carrier Transmission Services in a Disaggregated, Market-Oriented Electric Power Industry

1. *Regulatory and Legislative Changes*

In addition to changes called for in Scenario 4, the definition of the responsibilities of transmission companies as common carriers would require legislative and regulatory changes.

2. *Procedural Changes - Operating*

The operating changes described in Scenarios 1 to 4, (organization of an integrated Transmission Pool, with authority to control generating units for reliability and overall economy) would be required for Scenario 5 as well.

The Transmission Pool would, as a common carrier, have to integrate all the demands made on it by generation companies, whatever their origin, and others requiring wheeling, and to make whatever adjustments are needed to maintain the reliability of the transmission network. In order to do this, it may be necessary for the Transmission Pool to be integrated - horizontally - into an area-wide Transmission Company which would own all the transmission of what is now the PJM service area.

The procedures for coordination between generation, transmission, and distribution companies would have to be very carefully defined in their various contracts with each other.

3. *Procedural Changes - Planning*

The possible need for a horizontally integrated PJM Transmission Company has been discussed in the previous subsection. This is a planning consideration as well.

For the transmission company to be required to provide firm service without being given enough notice to allow construction would probably require a degree of transmission overbuilding that is grossly uneconomic, since this would imply building a transmission system that can transfer unknown amounts of power "from anywhere to anywhere," but that is used to perform only a fraction of what it is capable of doing. It is also unlikely to be feasible, given how much justification is needed in order to be permitted to build new lines. A more practical approach would be:

- To assure service if given sufficient notice to provide adequate lead time to build or reinforce facilities as needed.
- To require the transmission company to show cause if other transmission needs cannot be accommodated.

If additional transmission must be built in order to accommodate requests for future service, contributions in aid of construction should be required from the requestor, the amount depending on the project cost and:

- Whether the facilities would have been built otherwise; and
- Other potential users of the additional facilities.

4. *Technical Changes*

The need to provide common carrier service could, depending on the precise definition of the requirements for advance notice, require a moderate or very large increase in transmission facilities.

Lacking long-range generation plans as presently prepared by electric utilities, the needs for future transmission service cannot be predicted accurately, and the cost of maintaining duplicate facilities to provide service to all comers instantly would be exorbitant.

The needed transmission facilities can be built, given:

- Adequate time;
- Sufficient money; and
- Realistic and efficient resolution of environmental restraints.

APPENDICES

APPENDIX A

TRANSMISSION CONDITIONS IN VARIOUS AREAS

The following general review of transmission conditions in various parts of the United States is based particularly on material published by the North American Electric Reliability Council (NERC). The areas discussed are those for which transmission constraints have been identified in NERC reports.

1. Pennsylvania-Jersey-Maryland Interconnection

The Pennsylvania-Jersey-Maryland (PJM) Interconnection constitutes the majority of the NERC Mid-Atlantic Area Council (MAAC). The 1986 and 1987 NERC reliability reviews indicate that the primary transmission constraint in the area is the major west-to-east transmission path. During 1987, the PJM system was loaded to the limit of its capability to transfer energy west to east across PJM 96.8% of the time. However, analyses conducted in 1984 and 1985 by ECAR-MAAC for DOE show that the existing transmission system provided an estimated 90% of the economic benefits compared to what could be realized if the existing transfer capability were doubled.

An increase in nuclear capacity in MAAC in 1985-86 and the declining differential in oil/gas and coal prices have reduced the overall transfer of economy energy from regions to the west of MAAC, primarily the East Central Area Reliability Council (ECAR). However, internal transfers of energy along the west-to-east transmission path to serve the load centers in the East have maintained a high utilization of this path. This is especially true during daily peak load periods. The future changes in this transmission flow pattern are difficult to predict since they are heavily dependent on the change in oil prices. Relatively high oil prices would tend to increase the need for west-to-east transfers.

Utilities are finding it more and more difficult to expand the transmission system to meet future needs due to lengthening licensing processes, uncertainty regarding the cost/benefit relationship, conflicting jurisdictions, and a lack of incentives. A perfect example of this is the attempts to complete the Baltimore-Washington 500 kV transmission loop. Approximately 82% of the loop is currently in service with only two segments remaining to be completed, the Chalk Point-Calvert Cliffs circuit and the Brighton-Waugh Chapel circuit.

The Baltimore-Washington 500-kV loop is intended to fulfill two roles: to provide a path for economy power interchange, and to enhance system reliability by providing a path for emergency power transfers which may be required during major generation and transmission failures. The problems in obtaining the required authorizations for completing the loop represent an impediment to power transfers that has existed since at least 1979. These delays have been due to a series of maneuvers in regulatory and legal proceedings which have successfully delayed the granting of required authorizations for this entire period.

The difficulties experienced with the Baltimore-Washington loop will be complicated in the period between 1988 and 1996 due to the increased reliance on non-utility generators for new capacity. By 1996, approximately 6.2% of the total generating resources in MAAC could be non-utility generators. The location of these non-utility generators will be critical to the overall utilization of the west-to-east transmission corridor in MAAC. As this non-utility generation is added to the region, reliability could be impaired if significant non-utility generation is installed in areas where the utilities have not planned for the transmission capable of handling these capacity additions.

2. Southern California Edison Company

The Southern California Edison Company (SCE) is a member of the Western Systems coordinating Council (WSCC). The primary concern in the West is a disruption of the Pacific North-South Intertie. Loss of both 500-kV alternating current (AC) lines or both poles of the high voltage direct current (HVDC) line will result in serious bulk power supply problems within WSCC. Hydroelectric generation from the Pacific Northwest plays an important role in the energy supply picture in the Pacific Southwest. The loss of either the AC or HVDC transmission lines will adversely affect the SCE service area.

The NERC 1986 Reliability Assessment shows that over 31% of the planned capacity additions in WSCC between 1986 and 1995 will be non-utility generators.[1] As in MAAC, the size and location of these non-utility generators will be closely watched by the utilities within WSCC to ensure that the transmission system is capable of handling this diverse capacity source. The California-Southern Nevada area is predicting the highest growth in non-utility generation. A primary concern in this area is that, in most cases, the utility has no control over non-utility generation operations under current arrangements. The utilities are required to absorb the energy into their system whenever it is delivered by the non-utility generators. This requirement further complicates the overall operation and planning of the bulk power system in the WSCC.

3. Houston Light & Power

Houston Light & Power (HL&P) has very special considerations when addressing transmission constraints. HL&P is a member of the Energy Reliability Council of Texas (ERCOT). ERCOT is effectively isolated from the remainder of the transmission system in the U.S. One DC tie exists between ERCOT and the Southwest Power Pool (SPP) that can carry 200 MW of energy transfers and will be upgraded to a 300 MW line in 1989. An additional 600 MW HVDC tie to eastern Texas is being studied and, if installed, could be in place by 1990. Other than these tie lines, ERCOT relies totally upon internal generation for its energy.

A major concern for HL&P currently is the 345-kV transmission line to the Lower Colorado River Authority (LCRA), the Salem-Zenith line. This line is critical to support the bulk power transfers between HL&P and the LCRA. The Public Utility Commission of Texas rejected HL&P's request for a Certificate of Convenience and Necessity in November, 1987. HL&P has appealed the PUC's decision in the courts but a quick resolution is not anticipated.

Another concern is the de-energizing of the 345-kV line between HL&P and Texas Utilities (TU). This line was ordered de-energized in November, 1985 due to questions concerning the methods used by HL&P in obtaining the transmission

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[1] NERC, 1986 Reliability Review; Table 7, Pg. 15. –

right-of-way. In April, 1987 HL&P received Commission approval for rerouting the portion of the line that is being questioned and the new segment is anticipated to be in-service in late 1987.

4. Tennessee Valley Authority

There are several existing transmission constraints being experienced by the Tennessee Valley Authority (TVA). The TVA interface with the Mid-America Interconnected Network (MAIN) is a primary concern. This area (Joppa-Shawnee-Paducah) has experienced extremely high loadings in the past which have resulted in limitations on TVA's imports from MAIN. These limitations result from the large load at the DOE uranium enrichment facility in Paducah, Kentucky, generation levels at various nearby plants, and interregional and intraregional energy transfers. Currently, the problems are being mitigated by operational procedures that require tripping certain generators when line loadings get too high. Transmission additions could alleviate the problem, but none are planned due to the uncertainty of the future loads at the DOE facility.

The TVA-Southwest Power Pool interface in Memphis, Tennessee is sensitive to both west-to-east and north-to-south transfers. Of primary concern is the heavy loading of the Cordova-West Memphis 500-kV line. Some major EHV reinforcements planned during the 1987 to 1996 time period should reduce, but not eliminate, this constraint.

5. Southern Electric Company

The Southern Electric Company has two primary transmission areas of interest, the Southern-Duke interface (to Duke Electric Company) and the Southern-Florida interface (to Florida Power Corporation, Florida Power & Light Company, and Tallahasee Electric Department). The Southern-Duke interface in the area of the Savannah River is being affected by energy transfers between other adjacent and non-adjacent systems. Some transmission system enhancements in 1986 mitigated some of the problems, but operating procedures to reduce line loadings will be in effect for the foreseeable future.

The Southern-Florida interface is not currently a constraint but rather presents an area of surplus transmission capacity. Florida still plans to import approximately 2400 MW across this interface (total capability is 3500-4000 MW) through the 1987-1996 time frame. However, if oil prices increase significantly in the future, this interface will again approach maximum allowable loading for most hours in the year.

6. The Southwest Power Pool

The Southwest Power Pool (SPP) currently has no transmission constraints other than the Cordova-West Memphis line previously mentioned. In addition, current plans call for the installation of two new major interconnections. A third 500-kV line between SPP and SERC and a second HVDC line to ERCOT are planned for the 1987-1996 time period. These two lines, along with planned additions within the SPP, will greatly enhance the pool's import/export capability.

7. The East Central Area Reliability Council

The East Central Area Reliability Council (ECAR) has adequate transmission capacity in place to serve the next ten years with the addition of almost 100 miles of 500-kV and 300 miles of 345-kV lines planned. ECAR has an extensive 765-kV network which provides which provides high reliability within their region. The major problem within ECAR is the need to increase their transfer capability for exporting energy to MAAC.

8. The Mid-Continent Area Power Pool

The Mid-Continent Area Power Pool (MAPP) anticipates no major transmission bottlenecks in the next ten years. The primary concern is that energy transfers to the MAIN have occasionally been limited in order to ensure secure system operations. MAPP has plans for almost 2000 miles of additional transmission lines in the next ten years.

9. The Northeast Power Coordinating Council

The Northeast Power Coordinating Council (NPCC) is in the process of adding a major U.S.-Canada intertie. Phase I has been completed and interconnects Hydro-Quebec (HQ) to New Hampshire and is rated 690 MW. Phase II will upgrade the interconnection to 2000 MW and extend the line to eastern Massachusetts. Of major concern is the effect of the HQ-NEPOOL interconnection on the operation of the transmission systems of the PJM and NYPP. Operating guidelines are being developed jointly to ensure adequate reliability in the event of a trip on the HQ-NEPOOL interconnection. Heavy flows from Canada to NEPOOL are expected to continue for at least the next ten years.

There are two transmission concerns in New York. The first is the increased level of power transfers from upstate New York and Canada to Southeastern New York. A planned 200-mile 345-kV reinforcement will permit increased displacement of oil-fired generation in the southeastern part of the State and improve reliability. Second, a 345-kV cable reinforcement to Long Island is planned for 1991/1992 installation is needed to maintain reliability of service to the island.

APPENDIX B

EXPANDING TRANSMISSION CAPABILITY: CORRECTIVE TECHNOLOGY APPLICATIONS

Corrective technology, also called "remedial measures," are measures taken after a contingency occurs to prevent overloads, or excessive voltage drops, from interrupting or endangering service reliability. They are in contrast to the usual practice of "preventive mode" operation, in which operation of the system is restricted so that conditions after any single contingency will remain acceptable.

Remedial measures are generally aimed at a specific contingency, or at most, at a group of similar contingencies which have a common effect, such as overloading the same line.

Figure B-1 represents a section of the SCE 220-kV system. A large Qualifying Facility (QF) (an enhanced oil recovery project) was installed at Sycamore/Omar, with a firm output of 500 MW. The numbers with arrows along the various transmission lines show the loadings in megawatts. Under normal conditions, there are no actual overloads. However, if one of the three lines between Magunden and Pastoria substatious trips out, the loading of the remaining two lines increases to 380 MW each, which represents a 20% overload, as shown in Figure B-2. A preventive approach would call for reducing the generation in the North by approximately 200 MW so that the post-contingency flow of the two remaining lines would not exceed their ratings. Instead, a remedial measure was instituted so that SCE's hydro generation would be immediately reduced as required, and operators alerted to initiate manual action. SCE indicates that the efficacy of this scheme remains to be demonstrated when the QF project is completed.

FIGURE B-1

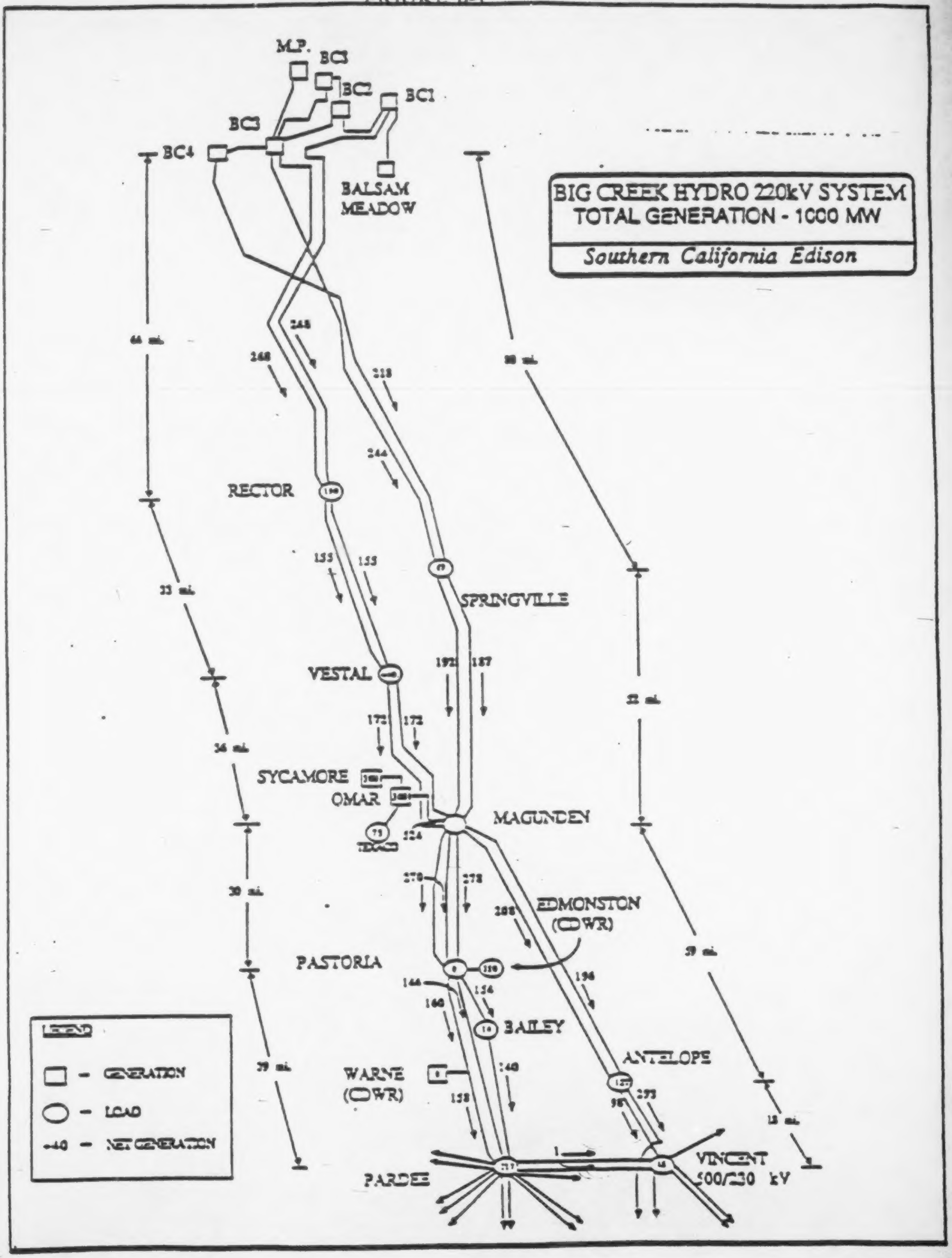
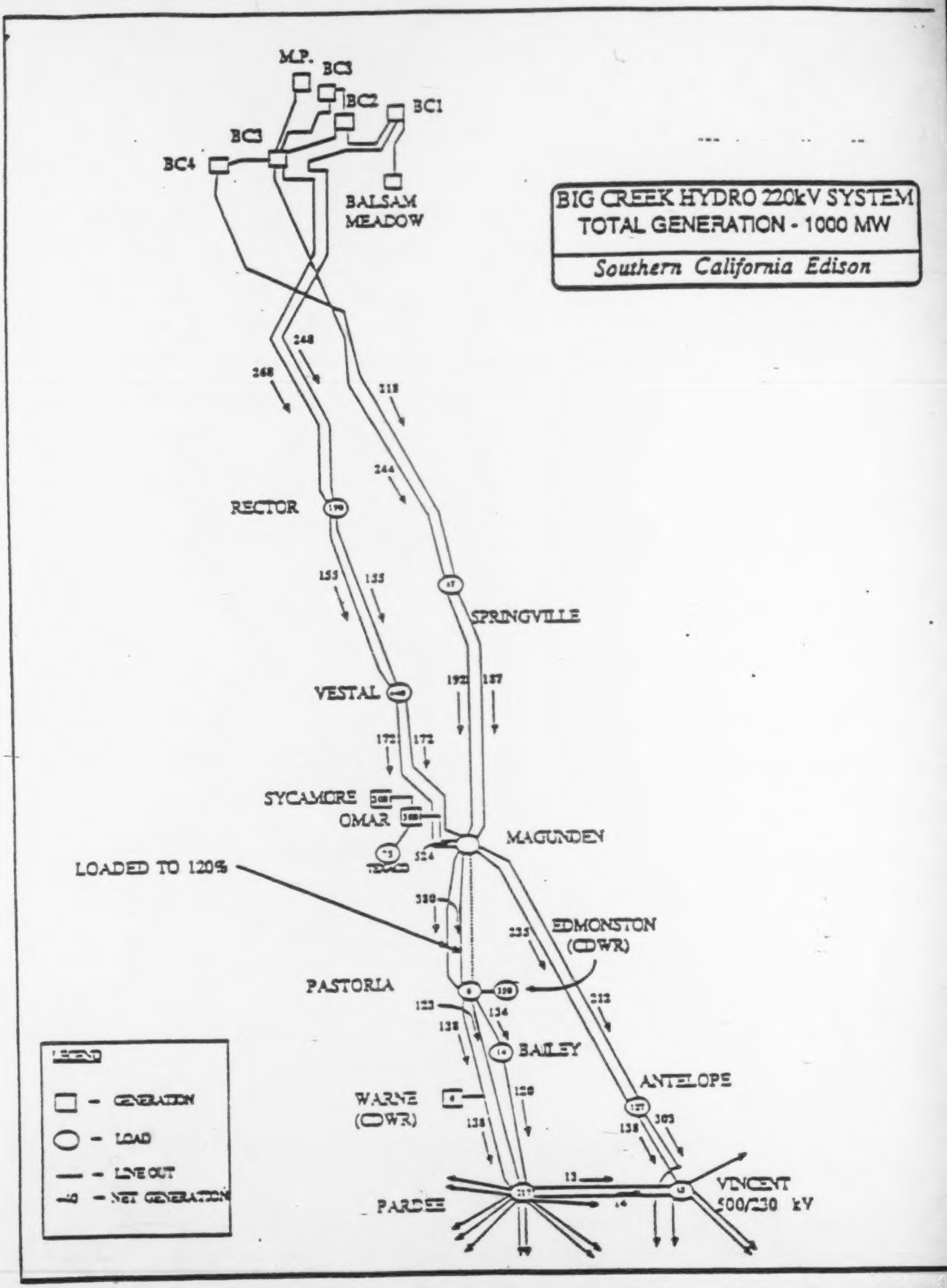

BIG CREEK HYDRO 220kV SYSTEM
TOTAL GENERATION - 1000 MW
Southern California Edison
M.P.
BC3
BC2
BC1
BC3
BC4
BALSAM MEADOW
66 mi.
248
248
218
244
90 mi.
RECTOR
155
155
SPRINGVILLE
33 mi.
VESTAL
192
187
52 mi.
172
172
34 mi.
SYCAMORE
OMAR
MAGUNDEN
73
TEXACO
224
278
278
30 mi.
EDMONSTON (CDWR)
208
59 mi.
PASTORIA
0
110
144
154
196
160
BAILEY
14
WARNE (CDWR)
0
140
ANTELOPE
39 mi.
158
98
293
18 mi.
1
PARDEE
VINCENT 500/230 kV
LEGEND
GENERATION
LOAD
+40 — NET GENERATION

FIGURE B-2


BIG CREEK HYDRO 220kV SYSTEM
TOTAL GENERATION - 1000 MW
Southern California Edison
M.P.
BC3
BC2
BC1
BC3
BC4
BALSAM MEADOW
248
268
218
244
RECTOR
155
155
SPRINGVILLE
VESTAL
192
187
172
172
SYCAMORE
OMAR
TEXACO
524
MAGUNDEN
LOADED TO 120%
338
235
EDMONSTON (CDWR)
PASTORIA
123
134
232
138
BAILEY
WARNE (CDWR)
128
ANTELOPE
138
138
303
13
14
PARDEE
VINCENT 500/230 kV
LEGEND
GENERATION
LOAD
LINE OUT
NET GENERATION

APPENDIX C

EXPANDING TRANSMISSION CAPABILITY: HVDC TERMINAL EXPANSION PROJECT

The 851-mile High Voltage Direct Current (HVDC) line from Celilo, in Oregon, to Sylmar, in Southern California (see Figure C-1) is one of the most important means of bringing low-cost power from the Pacific Northwest to California including Southern California Edison Company (SCE). At present the capacity of this line is 2000 NW, but the limitation is not in the line itself but in the terminals. The line itself would be able to carry 3100 MW based on its thermal capacity. The terminals of the line convert the power it carries from AC to DC at the sending end, and from DC back to AC at the receiving end. Adjustment of the controls permit the sending and receiving ends to be replaced, thus reversing the sense of the power flow.

HVDC lines are different in function and economic characteristics from high voltage AC lines in several important ways:

- The power carried is controlled at the terminals and is not directly affected by conditions on the AC parts of the system.
- Because the flow on the HVDC line is controllable, an increase in its capacity directly increases the transmission capacity of the system as a whole by the same amount.
- The terminals of an HVDC line represent a much larger fraction of the total cost than do the terminals of an AC line.

In the case of the Celilo-Sylmar line, the capacity of the line was increased by 1100 MW by adding DC terminal equipment (see Figure C-2). This brings the terminal capacity to match the line capacity, increasing the line capacity from 2000 MW to 3100 MW.

FIGURE C-1

HVDC EXPANSION

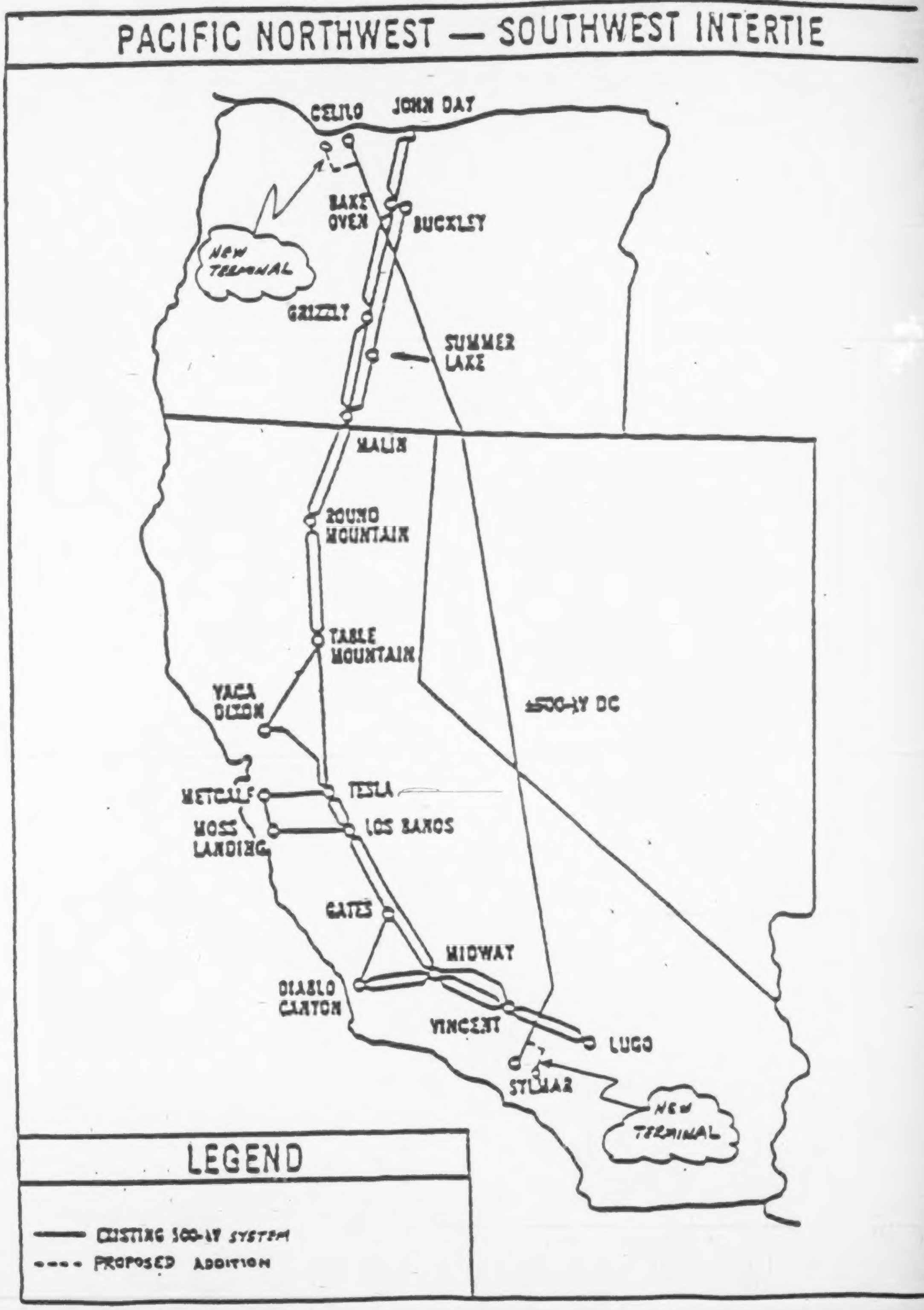
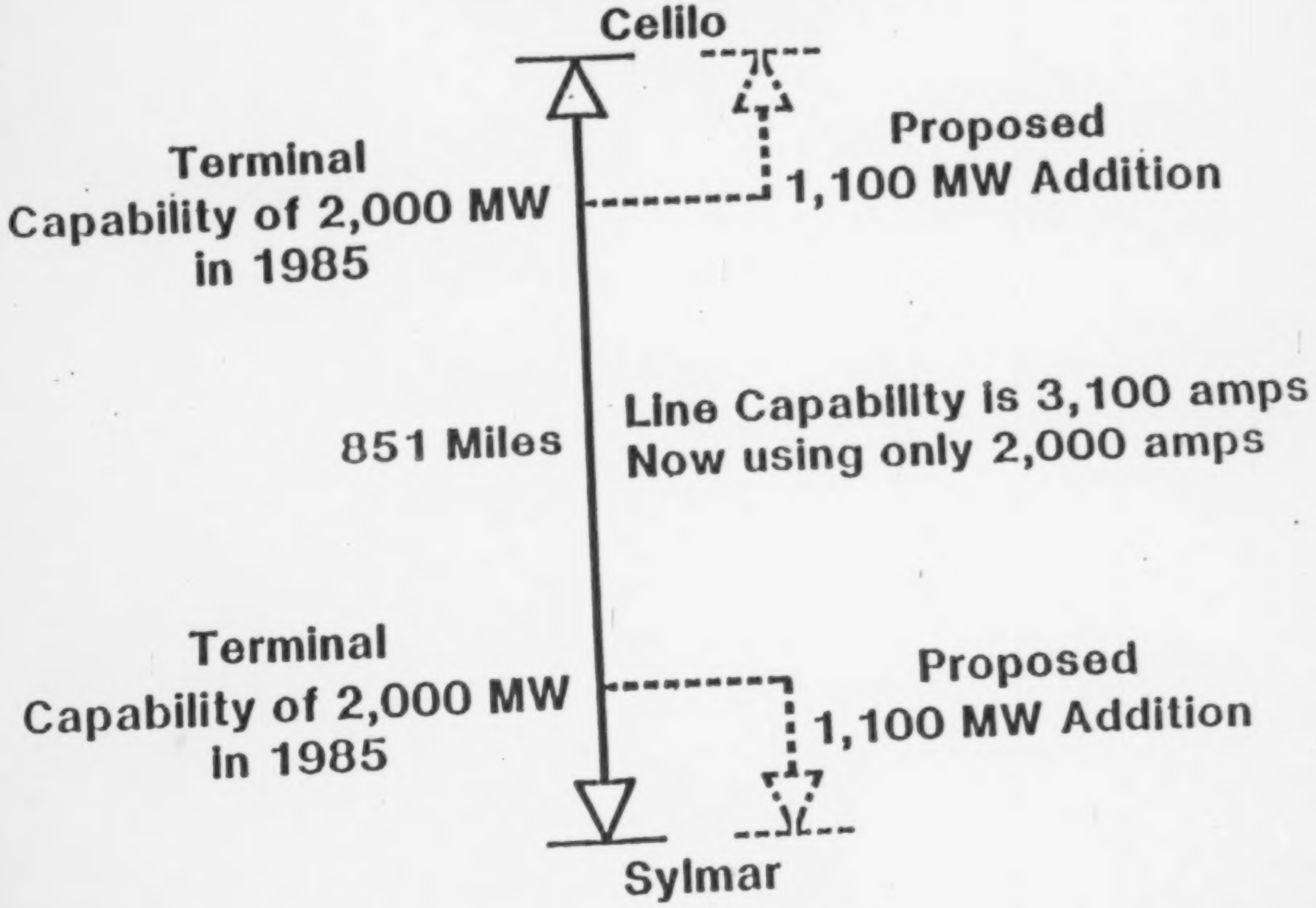

PACIFIC NORTHWEST — SOUTHWEST INTERTIE
CELILO
JOHN DAY
NEW TERMINAL
BAKE OVEN
BUCKLEY
GRIZZLY
SUMMER LAKE
MALIN
ROUND MOUNTAIN
TABLE MOUNTAIN
VACA DIXON
±500-KV DC
METCALF
TESLA
MOSS LANDING
LOS BANOS
GATES
MIDWAY
DIABLO CANYON
VINCENT
LUGO
SYLMAR
NEW TERMINAL
LEGEND
EXISTING 500-KV SYSTEM
PROPOSED ADDITION

FIGURE C-2

HVDC Expansion


Celilo
Terminal
Capability of 2,000 MW
in 1985
Proposed
1,100 MW Addition
851 Miles
Line Capability is 3,100 amps
Now using only 2,000 amps
Terminal
Capability of 2,000 MW
in 1985
Proposed
1,100 MW Addition
Sylmar

APPENDIX D

EXPANDING TRANSMISSION CAPABILITY: USE OF PHASE SHIFTERS

Topography of the WSCC System

The WSCC transmission system, taken as a whole, has the general shape of an elongated doughnut including a western section of lines joining Oregon and California, and an eastern section running generally from Montana to Arizona; these sections are joined, and the doughnut completed, by transmission in the Northwest and in Southern California - Arizona. Figure D-1 shows a simplified view of the WSCC doughnut.

Loop Flows

Because of the shape of the transmission system and of the laws of electricity, whenever power is sent from one part of the doughnut to another, the flow is split two ways; some go clockwise, and some counterclockwise. The proportion going each way depends on the relative impedance of the two paths. This impedance may be thought of as an "electrical length," which depends on the actual length and the voltage of the path (a mile of 500 kV line will have approximately one fifth the impedance of a mile of 230 kV line). For example, if 1000 MW of power is sent from the Montana-Wyoming area to the Pacific Northwest, only 580 MW of this power will flow along the relatively direct counterclockwise path, as seen in Figure D-2, and the remaining 420 MW will flow clockwise through California and north through the western lines. The flows due to simultaneous transactions carried on at the time will be superimposed on each other depending on their amount and direction. For example, a sale from the Northwest to California would reduce (or reverse) the flow in the west and between the Northwest and Montana-Wyoming, and increase the flow from Montana-Wyoming to California on the eastern lines.

FIGURE D-1

Western Interconnected System

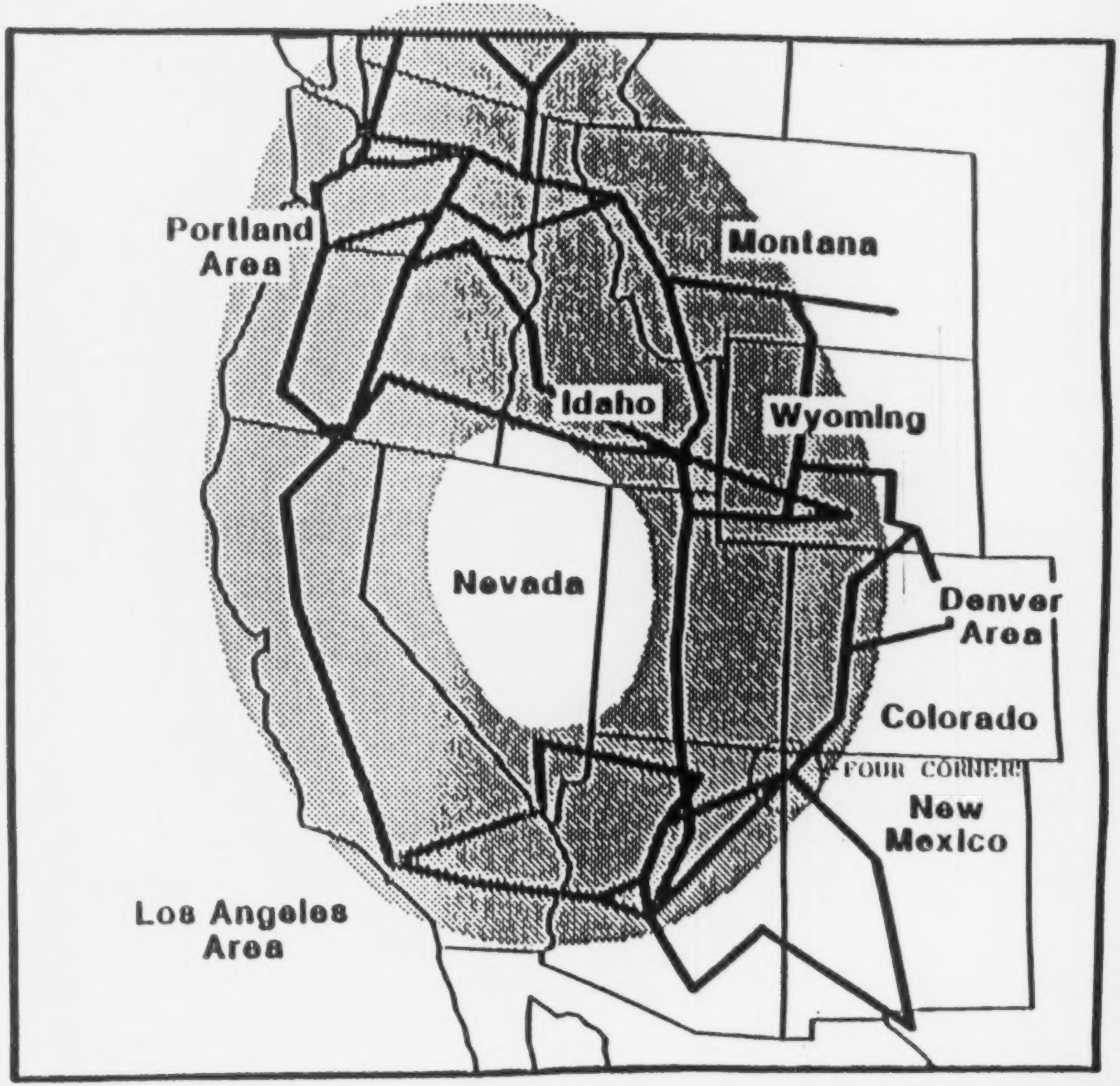
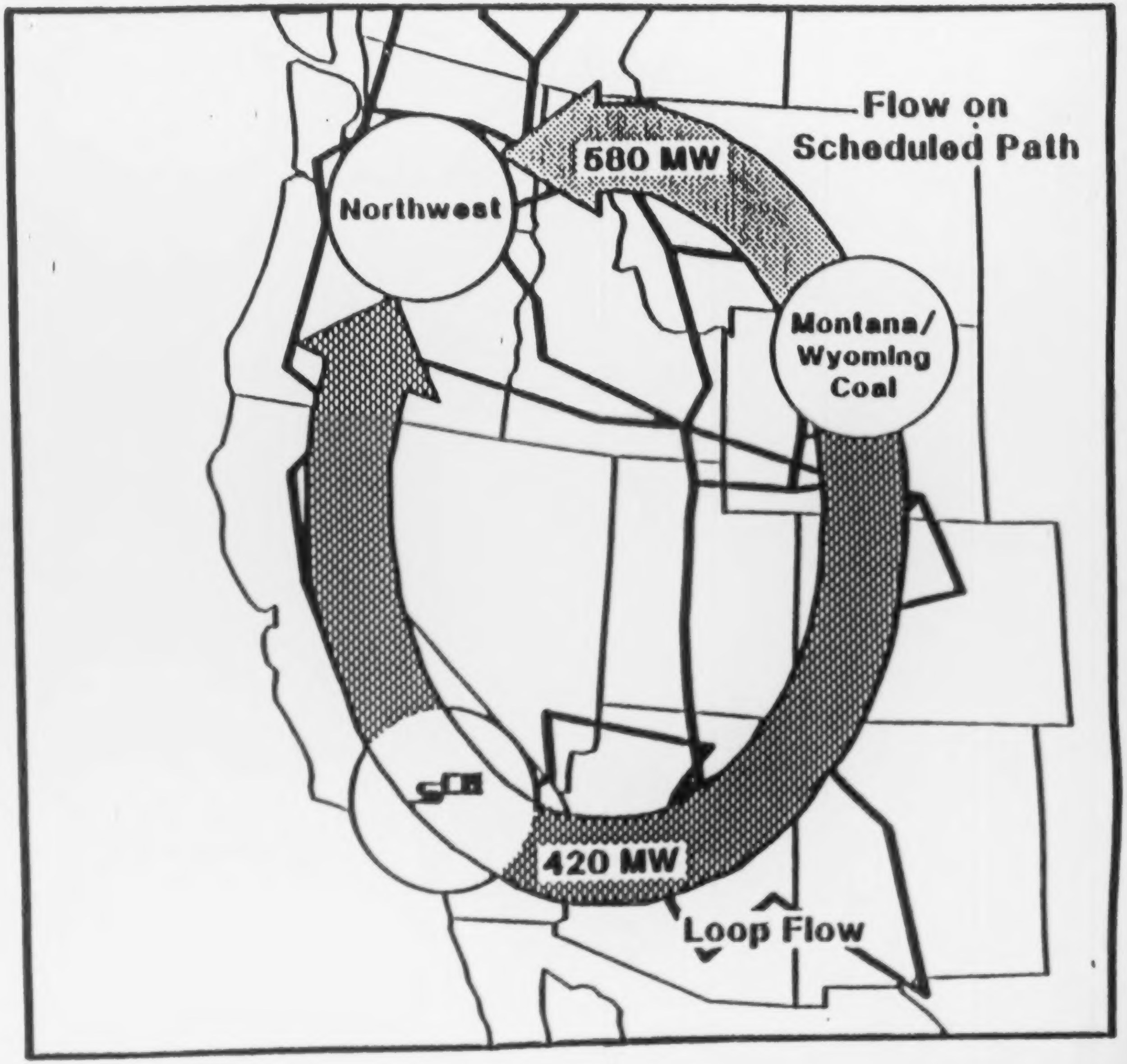

Portland Area
Montana
Idaho
Wyoming
Nevada
Denver Area
Colorado
FOUR CORNERS
New Mexico
Los Angeles Area

FIGURE D-2

Clockwise Loop Flow

Montana/Wyoming Coal Schedules to the Northwest
Schedule: 1000 MW


Flow on Scheduled Path
580 MW
Northwest
Montana/ Wyoming Coal
420 MW
Loop Flow

If the Montana-Wyoming to the Northwest transaction used a "scheduled" or "contract path" directly joining the two areas, the 420 MW flow not using that path is called a clockwise "loop flow."

Application of Phase Shifters

Phase shifting transformers, commonly called phase shifters, are transformer-like devices which inject a voltage in a line which forms part of a transmission loop. The effect of the phase shifter is to induce power flows in the loop, so that the power flows in the loop are increased or decreased, depending on the setting of the transformers. For example, in the situation shown in Figure D-2, phase shifters could induce a counterclockwise flow of, say, 100 MW which would increase the flows on the scheduled path to 680 MW and reduce the flows on the rest of the loop to 320 MW. The amount of power flow that is redirected depends on the size, number, and locations of the phase shifters and on the impedances of the lines forming the loop.

Purpose of the Phase Shifter Study

In 1986, a WSCC task force performed a study of the effect of phase shifting on transfer capabilities throughout WSCC. The Western Area Power Administration had plans to install phase shifters on two lines in Western Colorado, the task force studied the effect of installing two or four phase shifters in the eastern side of the "doughnut." The studies concerned the effect of the phase shifting on clockwise loop flows. Transient stability was the limiting consideration of transfer consideration.

Conclusion of the Study

The studies indicated that the phase shifters would improve the ability to schedule power from Colorado and Utah to the southwest, and they would not reduce the transfer capability between the Northwest and California, but they would have some negative effects also. Specifically, the study found:

- No reduction of NW/California transfer capability with two or four phase shifters for the conditions studied. In addition, Northwest remedial actions may need to be reviewed. For constant scheduling levels, there will be more reliance on Northwest generator dropping.

- A reduction in the Arizona/California - East of the River (EOR) transfer capability of 0 to 300 MW for four phase shifters and 0-150 MW for two phase shifters. These reductions depend on the phase shifter angles, the NE/SE actual flow, and schedules between areas.

- No reduction in either the Utah or western Colorado portions of the NE/SE transfer capability. Arming of the Huntington unit trip scheme (a "remedial measure") will be required more often with two phase shifters than with none.

- The transfer limit in western Wyoming may be reduced up to 30 MW with four phase shifters. There is no reduction in the transfer limit with two phase shifters.

Other impacts of phase shifters based on the conditions studied are as follows:

- Total WSCC losses go up as the phase shifter–angles are increased in the direction so as to reduce clockwise loop flow through Utah/Colorado. Individual area losses may go up or down depending on the redistribution of the flows due to the phase shifters.

- In general, two or four phase shifters can be used to increase schedules by the amount of loop flow reduction up to the transfer capability of the path. Study results indicate two phase shifters can change the loading of the lines from Colorado and Utah to the southwest by at least 300 MW and four phase shifters can change this loading by at least 500 MW.

- Using two phase shifters in Colorado to redirect loop flow off of the Colorado lines could cause a reduction in Utah's scheduling capability to the south.

- Reductions in transfer capability might be offset by an increased ability to carry scheduled power across a boundary. For example, assuming operation of the four phase shifters reduced EOR capability by the maximum noted above, 300 MW, studies indicate at the phase shifters maximum angles the clockwise loop flow across the EOR would also be reduced by approximately 500 MW. This would result in a net increase of approximately 200 MW in the system's ability to carry scheduled power across the EOR path.

APPENDIX E

EXPANDING TRANSMISSION CAPABILITY: ALTERNATIVES TO SECOND PALO VERDE - DEVERS 500 KV LINE

A recent study by SCE considered a number of ways to increase import capability from Arizona. The method of the study was to compare a number of alternatives to the base project, which was to build a second 500-kV line from Palo Verde, Arizona to Devers, California.

Eight alternatives were considered. Their nature, and the conclusions reached about them, were the following:

1. Loop flow corrective measures: a 1000 MVA phase shifting project at Vincent Substation
2. Measures to prevent subsynchronous resonance (SSR) while increasing series compensators on the lines between Arizona and California.
3. Interconnection with the "Southwest Powerline"
4. Using available capacity on the existing Palo Verde-Devers line (now being used for cost-effective short-term transactions with Southwest utilities)
5. Increasing load management and conservation
6. Increasing the implementation of minimum-load corrective measures
7. Converting the existing Palo Verde-Devers line to 765 kV AC
8. Converting the existing Palo Verde-Devers line to 500 kV DC

Of the eight alternatives, four (Nos. 5-8) were determined to be unfeasible: Table E-1 gives the reasons. The capital costs and associated transfer benefits for strategies identified as being feasible are summarized in Table E-2. In addition, a number of mixed strategies involving two of the feasible alternatives were evaluated, with results shown in Table E-3.

The study concluded that the mixed strategy of increasing series compensation and interconnecting with the Southwest Powerline was the best of the alternatives considered. However, it was still found inferior to the proposed Devers-Palo Verde #2 project on the basis of

	Devers-P.V. #2	Mixed Strategy Alternative
Increased Transfer Capability	1200 MW	700 MW
Cost per kW of Increase Transfer Capability	$206/kW	$509/kW
Environmental Impact	Devers P.A. #2	Valley-Miguel line (shorter, but worse impact)

TABLE E-1

STRATEGIES IDENTIFIED AS NOT FEASIBLE

STRATEGY	REASON FOR DESIGNATION AS NOT FEASIBLE
CONVERTING DEVERS—PALO VERDE #1 TO 765KV AC	THE 500KV LINE CANNOT BE UPGRADED TO 765KV; IT WOULD HAVE TO BE REBUILT, REQUIRING A TWO YEAR OUTAGE
CONVERTING DEVERS—PALO VERDE #1 TO 500KV DC	COST OF A 2500MW CONVERSION (ADDING 1300MW OF TRANSMISSION CAPACITY) WOULD BE $747.5 MILLION. (SEE TABLE 10-10)
INCREASING LOAD MANAGEMENT AND CONSERVATION MEASURES	INCREASING LOAD MANAGEMENT AND CONSERVATION IS NOT COST-EFFECTIVE
INCREASING IMPLEMENTATION OF MINIMUM LOAD CORRECTIVE MEASURES	WITHOUT PROPOSED PROJECT, MINIMUM LOAD CORRECTIONS WILL NOT INCREASE SOUTHWEST ECONOMY ENERGY PURCHASES

TABLE E-2

MIXED STRATEGY ALTERNATIVE
FEASIBLE STRATEGIES

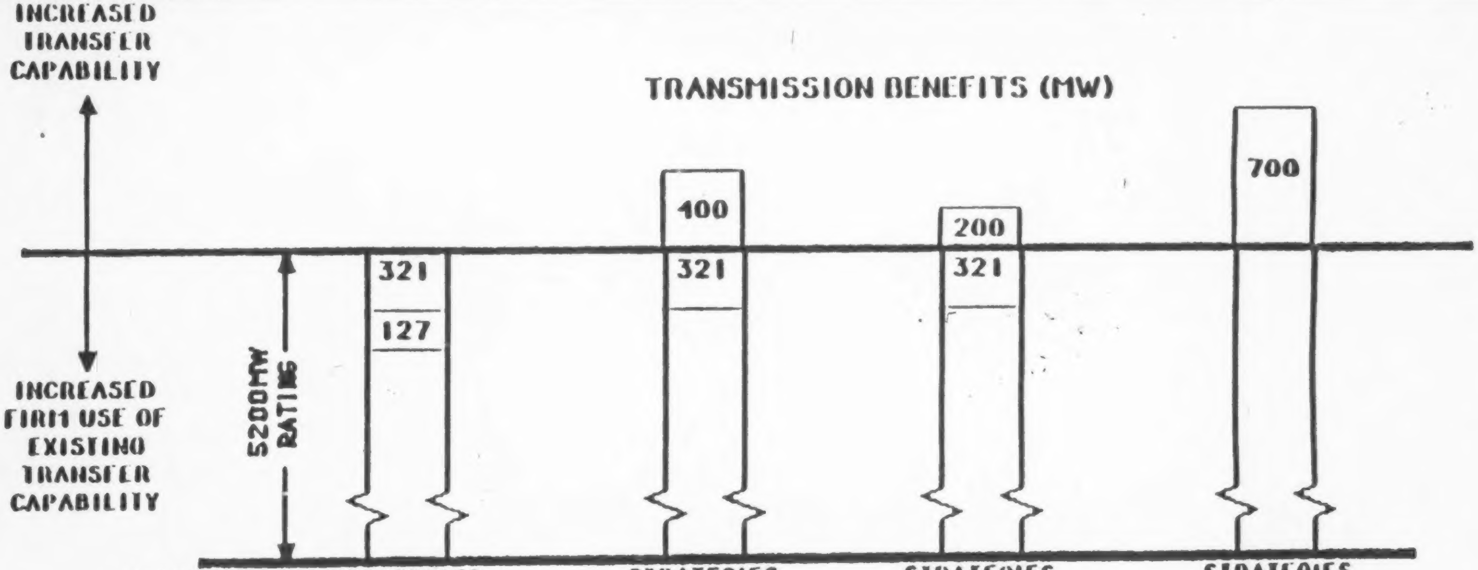
STRATEGY	TRANSMISSION BENEFIT (MW) INCREASED CAPABILITY	TRANSMISSION BENEFIT (MW) FIRM USE OF EXISTING CAPACITY	CAPITAL COST (SEE NOTE 1) $MILLION	CAPITAL COST (SEE NOTE 1) $/KW
LOOP FLOW CORRECTIVE MEASURES		127	60.3 (SEE NOTE 2)	475
SSR CORRECTIVE MEASURES WITH INCREASED SERIES COMP	400		117.8	295
INTERCONNECTING WITH SOUTHWEST POWERLINK	200	(SEE NOTE 3)	230.2	1191
USING AVAILABLE CAPACITY ON DEVERS-PALO VERDE #1		321	--	--

NOTES

1. COSTS OF LOST POWER PURCHASE OPPORTUNITIES ON EXISTING TRANSMISSION CAPACITY ARE NOT INCLUDED IN THESE ESTIMATES.
2. COSTS AND REQUIRED LEVELS OF ADDITIONAL VOLTAGE SUPPORT HAVE NOT BEEN DETERMINED.
3. SAN DIEGO GAS & ELECTRIC INDICATES NO ADDITIONAL CAPACITY IS AVAILABLE ON SOUTHWEST POWERLIN

TABLE E-3

MIXED STRATEGY ALTERNATIVE-BENEFITS AND COSTS



STRATEGY	STRATEGIES 1 & 4	STRATEGIES 2 & 4	STRATEGIES 3 & 4	STRATEGIES 2 & 3
	CAPITAL COST - MILLION $			
1. LOOP FLOW CONTROLS	$60.3			
2. SSR CONTROLS & SERIES COMP.		$117.8		$117.8
3. TIE TO S.W. POWERLINK			$238.2	238.2
4. USE AVAILABLE D-PV#1 CAP'Y.	--	--	--	
TOTAL	$60.3	$117.8	$238.2	$356.0

NOTE: THESE COSTS DO NOT INCLUDE LOST OPPORTUNITY COSTS ON EXISTING TRANSMISSION CAPACITY.

EXPANDING TRANSMISSION CAPABILITY: RAPID ADJUSTMENT OF NETWORK IMPEDANCE

As was discussed in Section III, electric power flows divide along parallel paths in reverse ratio to the impedance ("electrical length") of the paths. The Bonneville Power Administration has studied a proposed technique for increasing power transfer limits on power systems, contemplating its application to the Pacific Northwest-Southwest 500 kV AC interties.

The technique is called "Rapid Adjustment of Network Impedance (RANI)." It has the potential to improve AC power transmission practice in terms of increase in transfer capability, better transient and dynamic stability performance, improved damping of unwanted oscillations, control of power on transmission lines to get optimal powerflow conditions and to minimize unscheduled powerflows, and reduction in transmission lines.

RANI would be used on long transmission lines which already have a substantial amount of series capacitor compensation. Series capacitors are devices installed on transmission lines which reduce their apparent impedance and make them behave as through they were much shorter. It would make it possible to change the effective impedance of the line, based on automatic controls, very rapidly, presumably in a small fraction of a second.

RANI consists of a reactor (a device which increases the effective impedance of a line) which is controlled by thyristors (an industrial electronics device which permits stopping and starting currents at precisely timed intervals). The thyristors control the fraction of the time that the reactor carries current, and thereby control the effect of the reactor, which in turn controls the effective impedance of the line to which it is connected. The thyristors are controlled from automatic signals indicating the line impedance that is wanted.

The study indicated that the RANI device would increase transfer limits by controlling loop flows and also help in damping oscillations that have interfered with WSCC transmission operation in the past.

CASE STUDIES OF
TRANSMISSION BOTTLENECKS

Presented to the

Office of Technology Assessment
U.S. Congress

By:

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November 30, 1988

PREFACE

At the request of the Office of Technology Assessment (OTA) of the United States Congress, Casazza, Schultz & Associates, Inc. (CSA) has performed two case studies illustrating two types of problems and solutions associated with transmission bottlenecks.

OTA selected two cases from a list of potential cases provided by CSA. These were:

Case 1: Importing Power From Canada to New England (The "Phase II Project")

Case 2: Transmission to Deliver Low-Cost Power to El Paso Electric Company

These cases were selected because they illustrated specific transmission bottlenecks presently faced by the U.S. electric power industry. The bulk of the data used came from documents in the public domain, although selected industry spokespersons consulted for clarifications and additional information. Neither the OTA or CSA specifically endorses the solutions that were chosen. Nor does either organization claim that these specific case examples are representative of other situations in the United States.

CASE STUDY NUMBER 1

IMPORTING POWER FROM CANADA TO NEW ENGLAND

Presented to the

Office of Technology Assessment
U.S. Congress

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IMPORTING POWER FROM CANADA TO NEW ENGLAND

TABLE OF CONTENTS

SUMMARY 1

THE PROBLEM 2

PROPOSED SOLUTION TO THE PROBLEM 12

BENEFITS OF THE PROPOSED SOLUTION 15

COSTS AND NET BENEFITS OF THE PROPOSED SOLUTION 17

INTERREGIONAL IMPACT OF HYDRO-QUEBEC TO NEPOOL TRANSFERS . . 21
    Economic Consequences of Transfer Limitations 25

CONCLUSION 26

CASE STUDY NUMBER 1

IMPORTING POWER FROM CANADA TO NEW ENGLAND

SUMMARY

The availability of low-cost hydro power in Quebec Province and the relatively high costs of power in New England make the importation of power from Quebec to New England economically attractive. A High-Voltage DC connection is needed because the Hydro-Quebec system is not synchronized with the US-Canada Eastern Interconnection. The "Phase II" agreement between Hydro-Quebec and the New England Power Pool (NEPOOL) calls for the import of as much as 2000 MW of power. In order to implement this agreement, the capacity of the existing DC connection has to be increased, because the present tie capacity is limited to 690 MW. In addition, the 345-kV A-C transmission system in New England has to be expanded to carry the additional power to central and southern New England.

The increased imports from Canada would have an impact on the operation of other regional systems, resulting in a second transmission limitation. Under certain conditions, the Canadian imports must be restricted in order to avoid potential transmission problems in the Mid-Atlantic area and, perhaps later, in New York State.

The imports of Quebec power into New England are estimated to produce capacity and energy savings to New England with a present value of $1,849 million over the period 1990 to 1999. The total capital cost to New England utilities of importing this energy, representing the cost of transmission upgrades and relocations and new facilities, all in the United States, i.e., $547 million. The present worth of associated revenue requirements is $901 million.

Hydro Quebec, the Canadian utility that is selling the energy, will pay for the required expansion of Canadian facilities. These consist of accelerating the building of, generation facilities in the James Bay area of northern Quebec province accelerating the expansion of the transmission system in Quebec, and building additional AC-to-DC conversion facilities.

THE PROBLEM

The northeastern United States are facing shortages of power resources, and especially of low-cost ones, in the next few years. There are, however, ample resources of relatively low-cost power in Canada. The electric transmission systems of Quebec and New England operate separately and cannot be linked except by high-voltage D-C (HVDC) ties.

Table 1 shows the peak load and the components of generating capacity expected to be in service in 1990, and annual capacity margins for New England and neighboring areas. These areas are shown in Figure 1. Table 1 shows that New England will have relatively low generation reserve margins in 1990, indicating that additional capacity will be needed soon after to serve additional load growth. It also shows that New England will still have a particularly high proportion of oil-fired generation, which produces high-cost energy. The coal used for generation in New England is relatively expensive because of the cost of its transportation and the need to burn low-sulphur fuels for environmental reasons. All these factors indicate New England's need for additional capacity and energy resources, preferably at a lower cost than that obtained from New England oil or coal generation.

The Canadian province of Quebec has very large hydro-power resources. The James Bay area in the North, in particular, has been developed in anticipation of a growing need for electric power. Hydro-Quebec is the province's main electric utility and developer of electric power. Some of Quebec's hydro power exceeds its present needs, and is available at a lower cost than thermal power in the northeast United States, even when the cost of transmission from the distant generation sites to New England is included. The Province of Quebec and Hydro-Quebec have made it a policy to export power to the United States at profitable rates, as long as these exports do not interfere with industrial development of the province and are within the restrictions imposed by the Canadian national government.

TABLE 1
SUMMER 1990 GENERATION CAPACITY BY FUELS - MEGAWATTS

	ECAR	PJM	NYPP	NEPOOL	ONTARIO	NEW BRUNSWICK	QUEBEC
Nuclear	7,691	11,566	5,583[1]	6,552[2]	12,492	635	665
Coal	81,673	17,216	4,785	2,754	10,182	619	0
Oil & Gas	5,903	17,678	16,699	10,212	3,050	1,047	1,065
Hydro	73	1,148	4,021	1,318	6,171	884	22,988
Pumped Storage	3,583	1,280	1,000	1,594	0	0	0
Other	1,076	1,099	1,022	52	30	0	0
Total	100,662	49,987	33,110	22,482	31,925	3,185	24,718
Peak Load	74,340	39,481	24,700	18,256	18,737	1,575	16,510
Capacity Margin	26%	21%	25%	19%	59%	49%	33%

GENERATION CAPACITY – PERCENT OF TOTAL

	ECAR	PJM	NYPP	NEPOOL	ONTARIO	NEW BRUNSWICK	QUEBEC
Nuclear	7.6%	23.1%	16.9%	29.1%	39.1%	19.9%	2.7%
Coal	81.1%	34.4%	14.5%	12.2%	31.9%	19.4%	0.0%
Oil & Gas	5.9%	35.4%	50.4%	45.4%	9.6%	32.9%	4.3%
Hydro	0.7%	2.3%	12.1%	5.9%	19.3%	27.8%	93.0%
Pumped Storage	3.6%	2.6%	3.0%	7.1%	0.0%	0.0%	0.0%
Other	1.1%	2.2%	3.1%	0.2%	0.1%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

---

[1] Includes Shoreham, 809 MW

[2] Includes Seabrook, 1150 MW

Source: North American Electric Reliability Council "1987 Electricity Supply and Demand," Princeton, NJ, November 1987

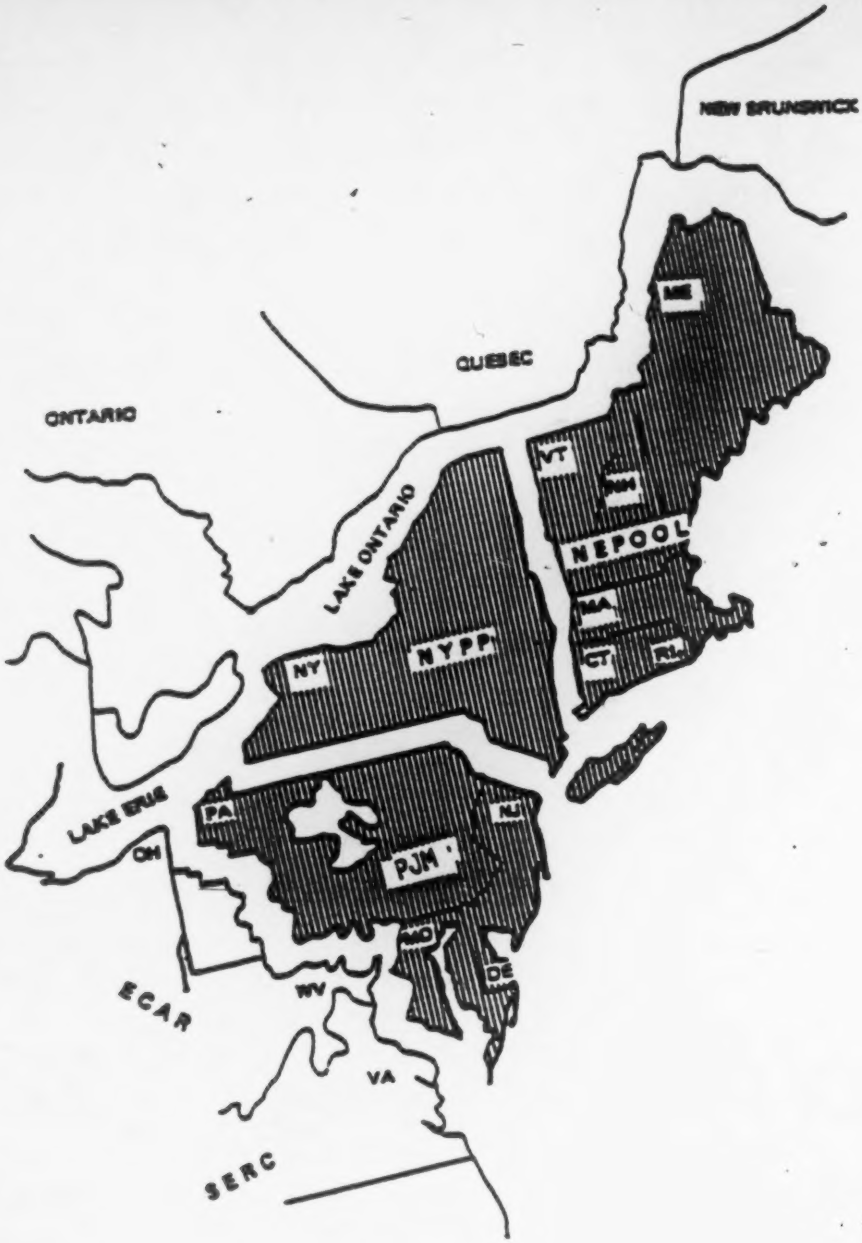
NEW BRUNSWICK
QUEBEC
ONTARIO
LAKE ONTARIO
ME
VT
NH
NEPOOL
MA
CT
RI
NY
NYPP
LAKE ERIE
PA
NJ
PJM
OH
MD
DE
ECAR
WV
VA
SERC

Figure 1

Affected Regions

The New York Power Pool (NYPP), with the New York Power Authority, operates the transmission system in New York State. New York utilities import substantial quantities of power from Ontario, from the Midwest (East Central Area Reliability Coordination Agreement [ECAR] region), and from Hydro-Quebec.

The Pennsylvania-New Jersey-Maryland Interconnection (PJM) region covers most or all of Pennsylvania, New Jersey, Delaware, Maryland and the District of Columbia. Its western region has substantial coal-burning generation, but the eastern areas still include a good deal of oil- and gas-fired generation. Consequently there are substantial cost incentives to transmit coal-generated power from the western PJM area and the ECAR region to the eastern part of PJM. Power from nuclear sources, which has the lowest incremental production cost of all except for hydro power, is normally not interchanged; it is used by owning systems to serve their own loads.

The Transmission Situation

The transmission systems of the various areas are connected with each other in order to permit the interchange of power for economy and reliability.

Hydro-Quebec operates the transmission system in the province, but this system is not operated in synchronism with that of the Eastern Interconnection[1], which includes all its neighbors. Figure 2 shows in simplified form the highest voltage lines (765 kV, 500 kV, and 345 kV) and the HVDC ties which form the backbone of the transmission systems of Hydro-Quebec and of the areas most directly affected by its exports. Not shown are underlying transmission lines operating at 230 kV and lower voltages. The 345-kV, 500-kV, and 765-kV lines represent the broad avenues of inter-regional power interchange.

---

[1] The Eastern Interconnection consists of all the electric systems of the continental United States and Canada east of the Rocky Mountains, except for Quebec and most of Texas. They all are electrically connected with each other through a network of AC transmission lines, so that all their generators operate in synchronism.

At present, the Hydro-Quebec system is connected to the rest of the Eastern Interconnection through five HVDC ties:

System	Location	Capacity
NYPP	Chateaugay	1,000 MW
NEPOOL	Highgate	200 MW
NEPOOL	Des Cantons	690 MW
New Brunswick	Madawaska	350 MW
New Brunswick	Eel River	350 MW
		2,590 MW

Their locations are shown in Figure 3. Each of these ties is adjustable to transmit any amount of power up to its capacity. It should be noted that the Province of New Brunswick, unlike Hydro-Quebec, operates in synchronism with New England. Therefore the interconnections between Quebec and New Brunswick must be HVDC.

Of the two present HVDC connections between Quebec and the NEPOOL system, one is a tie at Highgate in Vermont, which supplies up to 200 MW to the state of Vermont and some Vermont utilities. The other is the HVDC transmission associated with the Phase I project.

The Phase I Project

The Phase I project consists of a formal agreement for the sale by Hydro-Quebec to NEPOOL of 33 million MWh of surplus hydro-electric energy over an 11-year period beginning in 1986, and for providing the necessary transmission. This is an energy purchase agreement, which does not guarantee that NEPOOL will obtain any specified amount of power at the time of its most critical needs. However, NEPOOL does treat this agreement as reliable enough to justify not building 600 MW of capacity[2].

In addition, the Phase I agreement provides the opportunity for "energy banking," i.e. the delivery of energy from HQ to NEPOOL when HQ has surplus energy, to be returned when NEPOOL loads are lower and HQ loads are high.

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[2] "New England/Hydro-Quebec ± 450 kV Transmission Line Interconnection — Phase II," Final Environmental Impact Statement, US Department of Energy, Economic Regulatory Administration, Office of Fuel Programs, August 1987, available from National Technical Information Service, Springfield, VA 22161.

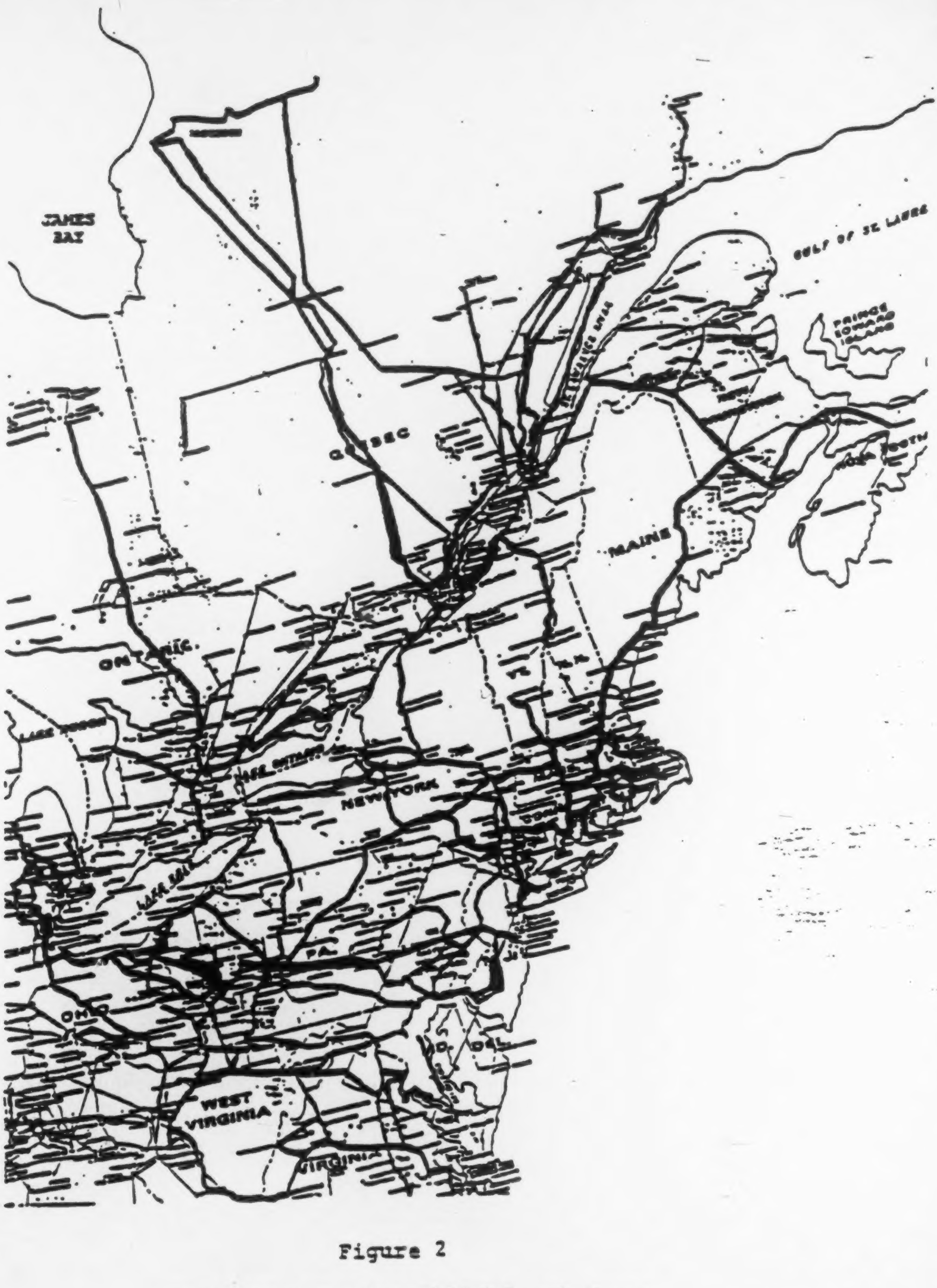

JAMES BAY
GULF OF ST. LAWRENCE
PRINCE EDWARD ISLAND
ST. LAWRENCE RIVER
QUEBEC
NOVA SCOTIA
MAINE
ONTARIO
VT.
N.H.
LAKE HURON
LAKE ONTARIO
NEW YORK
CONN.
LAKE ERIE
PA.
N.J.
OHIO
MD.
DEL.
WEST VIRGINIA
VIRGINIA

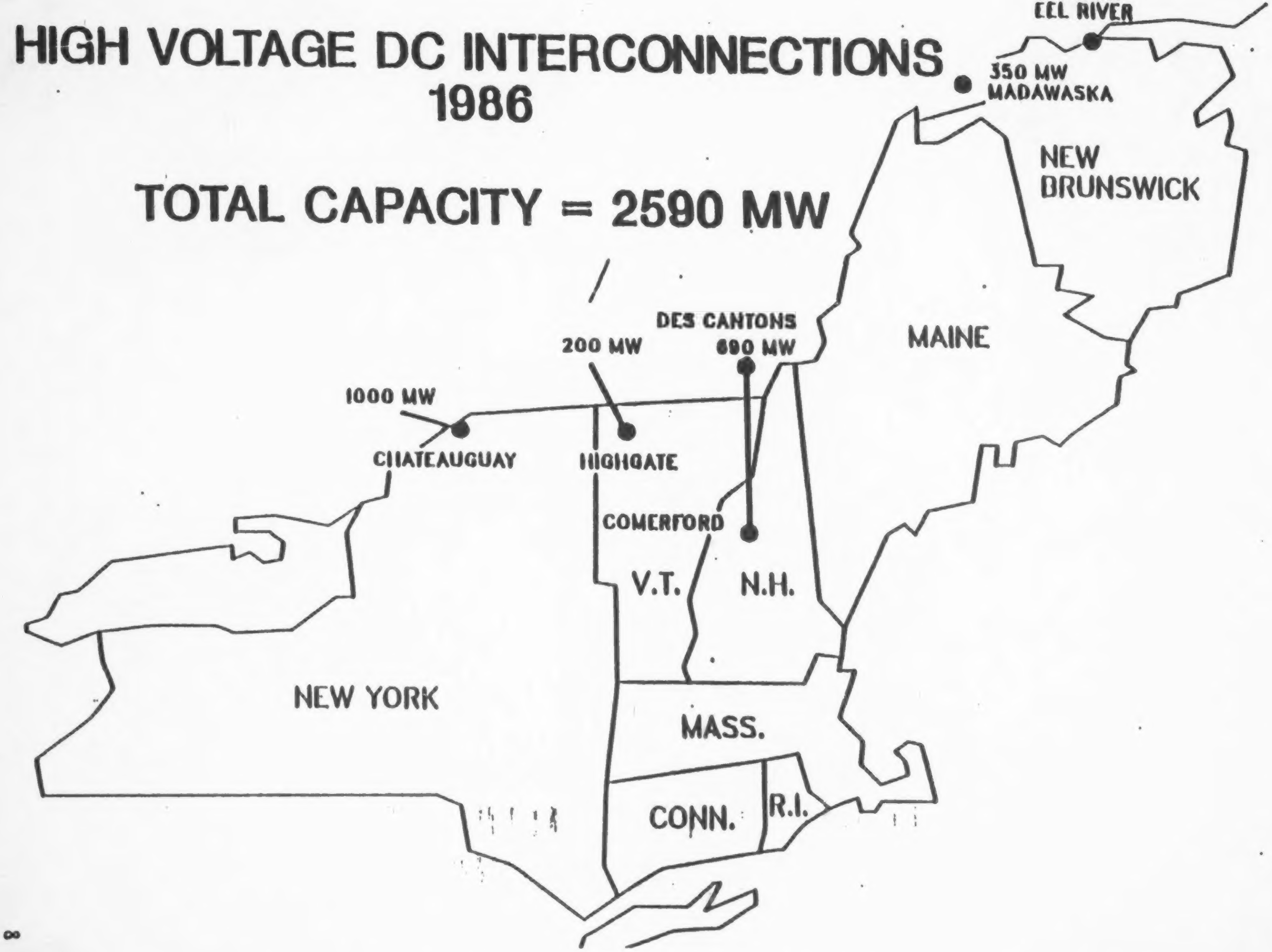
Figure 2

Transmission Lines 345 kV and Above

Figure 3

HIGH VOLTAGE DC INTERCONNECTIONS
1986

TOTAL CAPACITY = 2590 MW


350 MW
EEL RIVER
350 MW
MADAWASKA
NEW BRUNSWICK
MAINE
DES CANTONS
690 MW
200 MW
1000 MW
CHATEAUGUAY
HIGHGATE
COMERFORD
V.T.
N.H.
NEW YORK
MASS.
CONN.
R.I.

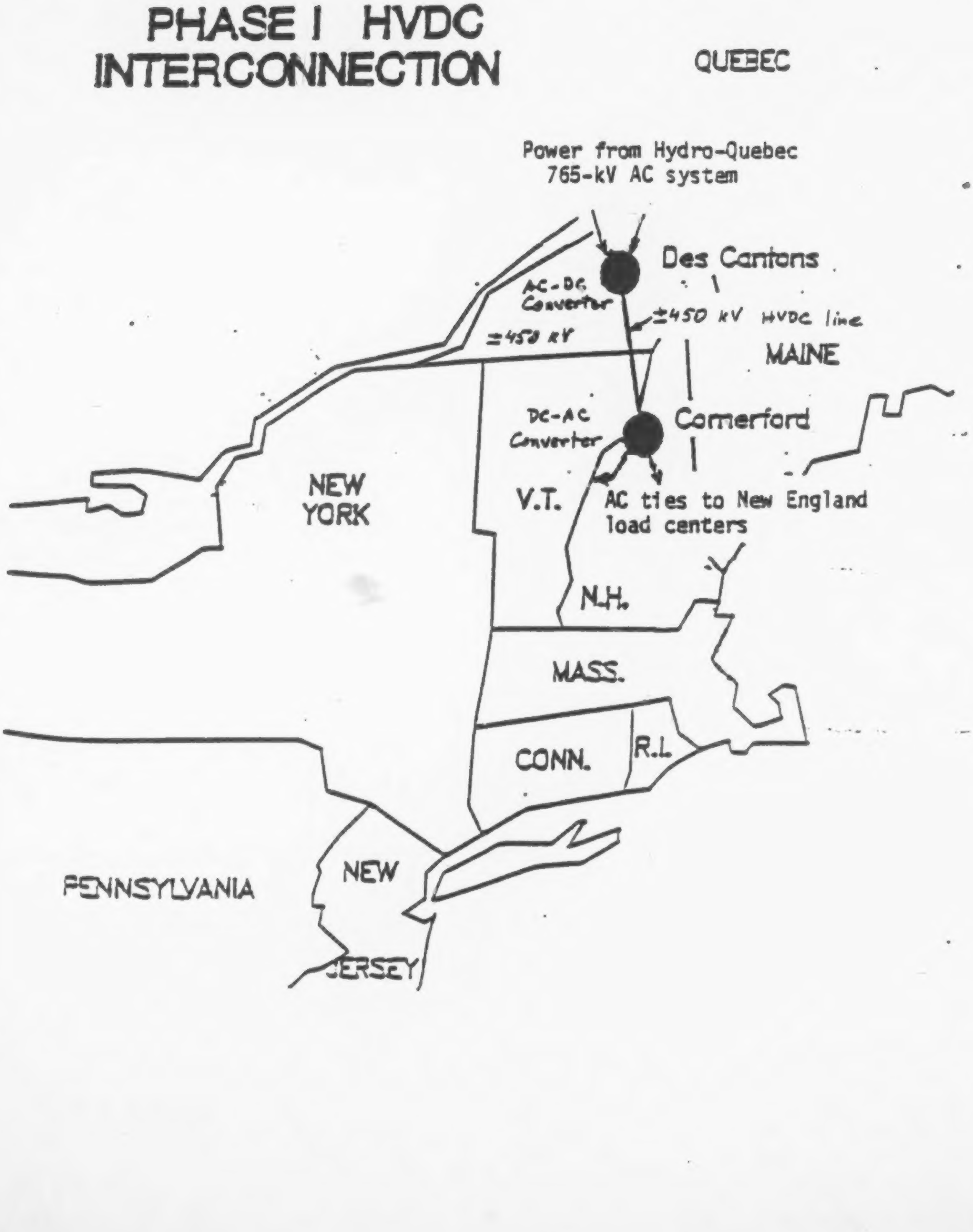
The Phase I imports, running to a maximum of 690 MW of power, are taken from the Hydro-Quebec 765-kV system at Des Cantons (see Figure 4), converted to ± 450-kV DC there, and transmitted over a 107-mile HVDC line through northeastern Vermont to Comerford, New Hampshire. At this point, the power is converted back to AC for transmission to the various loads in New England over NEPOOL's 345-kV and lower-voltage transmission lines. The capacity of the Des Cantons and Comerford converters is 690 MW each. The capacity of the HVDC transmission line itself is sufficient for it to carry the power flows of up to 2000 MW which will implement the Phase II project. The term "± 450-kV HVDC" denotes a transmission line consisting of two conductor wires, one carrying 450 kV positive with respect to ground, and the other 450 kV negative. HVDC ties are required between the HQ and NEPOOL systems because these two systems cannot be operated in synchronism for technical reasons. AC ties are feasible only between systems that operate in synchronism.

The Phase I project, as the name implies, was conceived as the first step in increasing power transfers from Quebec to New England. Under it, the HQ-NEPOOL transfers are limited by:

- Lack of an agreement to transfer more power.
- The limited capacity of the existing AC-DC converters at Des Cantons and Comerford.
- Limitations in the AC systems which bring power from the generation to Des Cantons, and from Comerford to the various load centers in New England (centered in eastern Massachusetts).

Increased imports can obviously not be carried out over the existing Phase I system.

Figure 4


PHASE I HVDC INTERCONNECTION
QUEBEC
Power from Hydro-Quebec 765-kV AC system
Des Cantons
AC-DC Converter
±450 kV HVDC line
±450 kV
MAINE
DC-AC Converter
Comerford
NEW YORK
V.T.
AC ties to New England load centers
N.H.
MASS.
CONN.
R.I.
NEW JERSEY
PENNSYLVANIA

The Phase I project transmission suffers from another drawback: with the present arrangement, about 15 percent of the power transferred at peak load times is dissipated in transmission losses. This is an unusually high amount, and reduces the economic benefits of the ties. It would appear that the AC systems on both sides were expanded only to the extent necessary to make the Phase I project viable, in the expectation of making more extensive improvements in connection with the Phase II development.

PROPOSED SOLUTION TO THE PROBLEM

The New England utilities have proposed to eliminate the bottleneck to the sale of additional low-cost energy to NEPOOL from Hydro-Quebec by building the transmission facilities required to accomplish this sale. This proposed transaction is commonly referred to as Phase II. It provides for a total additional energy purchase of 70 million MWh over a ten-year period, currently scheduled to begin in 1990, and for building the necessary transmission facilities for its delivery.

Hydro-Quebec is responsible for establishing the schedule of monthly deliveries of the 7 million MWH of energy over each contract year, while observing contractual monthly minimum and maximum limits. In general, NEPOOL is entitled to schedule deliveries in any hour up to the 2000-MW capacity of the tie. There are limitations on the rate of change of deliveries from one hour to the next, and Hydro-Quebec may interrupt deliveries during limited periods of time. This makes the Phase II agreement neither a completely interruptible energy purchase, such as Phase I, nor a firm capacity purchase agreement, which would guarantee the availability of specific deliveries when required by the buyer, subject only to forced outages and transmission limitations. In view of the terms and practical expectations of the Phase II agreement, NEPOOL considers that it represents a reliable capacity source of 900 MW, and that the combined Phase I and Phase II agreements can be treated as a replacement for 1500 MW of additional installed capacity[3]. This means that NEPOOL is confident that during its peak loads and other times of critical need, Hydro-Quebec will supply at least 900 MW of power under the Phase II agreement, at a reliability level compatible with that of other NEPOOL power resources.

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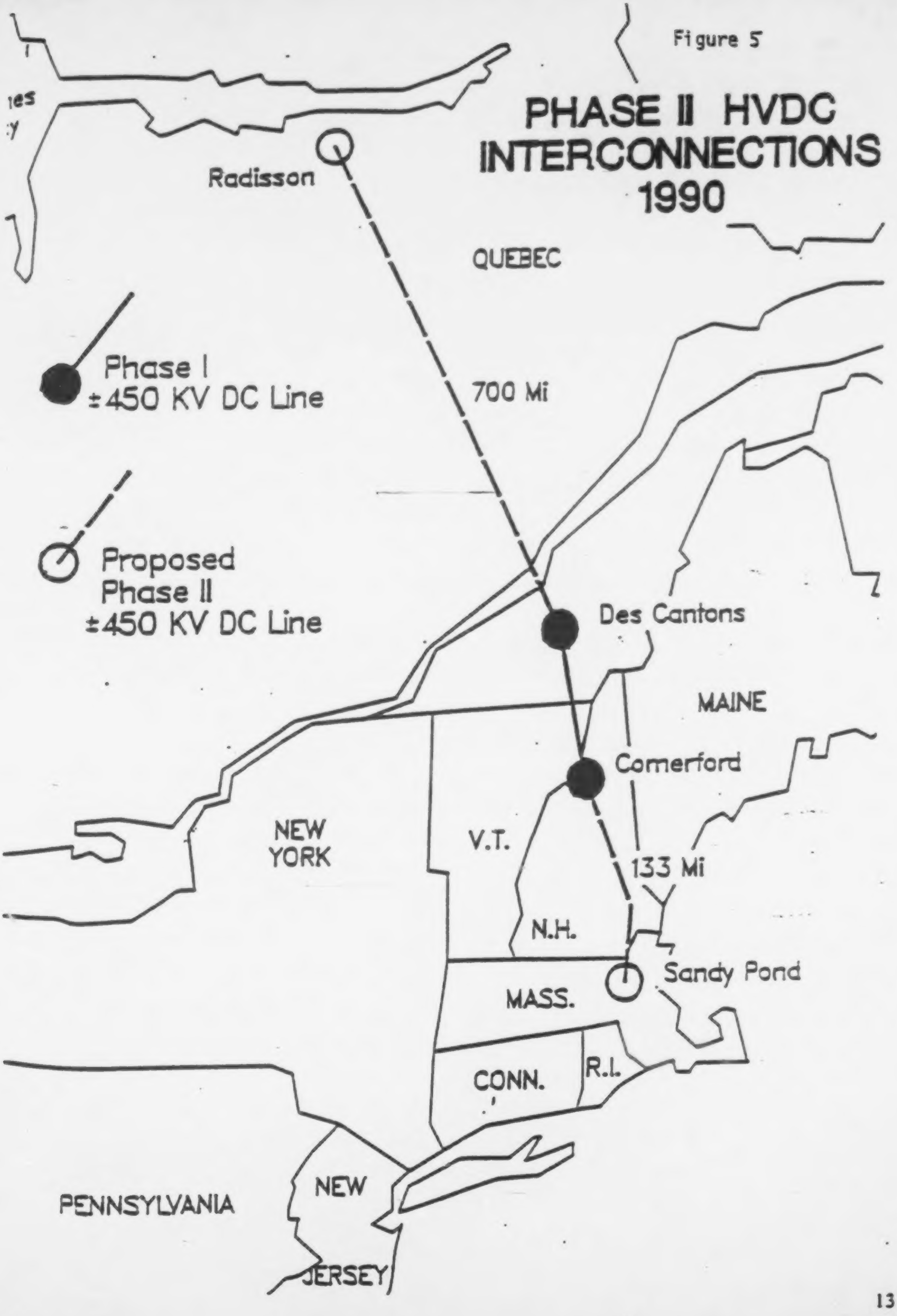
[3] New England Hydro-Transmission Electric Co., "Amendment to Supplement 2C to Long-Range Forecast 2 for the Ten-Year Period 1984-1993," submitted to the Massachusetts Energy Facilities Siting Council, November 1984, Volume 1, page 4.

The problem of the transmission limitations on Phase II imports is being resolved by adding both HVDC and AC components. In Canada, the HVDC components consist of a new 700-mile HVDC line from Radisson on James Bay to Des Cantons on a new right-of-way, and an AC-DC terminal (converter) at Radisson rated at 2000 MW. There will also be a DC-AC convertor at Nicolet, near Montreal, but this is only of internal significance to Hydro-Quebec. In the United States, there will be a 133-mile extension of the HVDC line from Comerford to an 1800 MW HVDC terminal at Sandy Pond in eastern Massachusetts. This line in the United States is entirely on existing occupied rights-of way, except for a short segment which is on existing utility property. The location of these facilities are shown in Figure 5. In addition, the NEPOOL AC system has to be expanded in order to absorb the Phase II power and distribute it to the various load centers in New England. The A-C expansion consists of constructing two new 345-kV AC transmission lines with a combined length of 51.8 miles, along existing transmission rights-of-way. One will lead from the Sandy Pond substation to Millbury substation in Millbury, Massachusetts, and the other from Sandy Pond to the West Medway substation in Medway, Massachusetts, near the Rhode Island border. Also, substantial substation reinforcements are required at the Sandy Pond, Millbury, and West Medway substations, as well as the moving of some low-voltage AC transmission on the Sandy Point to Millbury right-of-way, and other miscellaneous work.

As will be discussed later, the advantages to New England from this proposed solution could be offset by increased costs and transmission constraints in neighboring regions. These effects underline the importance of considering the impact of changes in any one region on both that region and other regions that may be affected. The costs and benefits of the proposed Phase II project will first be discussed from the perspective of New England alone. Subsequently, the adverse impacts of this project on neighboring systems will be described, and the associated costs and operating constraints will be discussed.

Figure 5



PHASE II HVDC INTERCONNECTIONS 1990

Radisson
QUEBEC
Phase I
±450 KV DC Line
700 Mi
Proposed
Phase II
±450 KV DC Line
Des Cantons
MAINE
Comerford
NEW YORK
V.T.
133 Mi
N.H.
Sandy Pond
MASS.
CONN.
R.I.
NEW JERSEY
PENNSYLVANIA

The price at which the energy is to be sold in each year is a specified fraction of NEPOOL's average fossil fuel (coal, oil, natural gas) cost in the previous year. This fraction is:

- 80% during the first five years of the contract; and
- 95% during the second five years.

BENEFITS OF THE PROPOSED SOLUTION

According to the Final Environmental Impact Statement (FEIS) for the Phase II project prepared by the Economic Regulatory Administration of the U.S. Department of Energy[4]:

> "the proposed action should provide economic benefits to the New England region in three ways: (1) a reduction in fuel costs through a reduction in the amount of oil used to generate energy; (2) a reduction of 900 MW in new generating capacity required to maintain the desired level of reliability on the NEPOOL system during the 1990's; and (3) a reduction in the electrical losses incurred when transmitting electric energy to the load centers in southern New England."

Since these savings depend heavily on the future price of oil, the FEIS presented the benefits of the Phase II project calculated for a "base" assumption concerning the future changes in fossil fuel prices, based on fuel cost projections developed for NEPOOL by Data Resources, Inc., revised in March of 1986, and for four other alternative trends (ranging from 65% below to 25% above the projected base trend). For the "base" assumption as to fuel cost trends, the present worth of the "gross" benefits (which do not reflect the costs of the project) are calculated to be:

	Millions of Dollars
Fuel cost savings	1,415
Capacity credit	407
Incremental loss savings	27
Total Gross Savings	1,849

---

[4] "New England/Hydro-Quebec ± 450 kV Transmission Line Interconnection — Phase II," Final Environmental Impact Statement, US Department of Energy, Economic Regulatory Administration, Office of Fuel Programs, August 1987, available from National Technical Information Service, Springfield, VA 22161.

All figures above represent the present worth of the indicated quantities over the contract period. They were presented by the applicant for the Presidential Permit to implement the Phase II imports, Vermont Electric Transmission Company, a member of NEPOOL, and reviewed and found to "appear to be reasonable" by the U.S. Department of Energy.[5] The capacity savings reflect the cost of installing 900 MW of combustion turbines in New England. Combustion turbines were considered to be a reasonable "second-best" alternative, in the words of the FEIS:

> "since gas turbines have a relatively low capital cost, are quickly installed, and are installed (generally) for reliability reasons only. Furthermore, if the Phase II projects were not undertaken, gas turbines are the only central station capacity source that could be installed in the required time period."

The tabulated "gross" benefits do not reflect the costs of the project, which will be covered later.

Hydro-Quebec, of course, also benefits from the Phase II transaction. It is selling energy which would otherwise be undeveloped. Its gross benefits consist essentially of the price received for the energy sold.

It has been correctly stated, on many occasions, that for true savings to be obtained from any electric power transaction, this transaction must result in a physical change in the overall dispatch, with generation increased at a lower-cost source, and decreased at a higher-cost source. Lacking this condition, there are no real savings, but merely a redistribution of costs. The Phase II project clearly passes this test. Comparing the Phase II project with its alternative, in which New England would install more combustion turbines, under Phase II, there will be more (low-cost) hydro power generated at James Bay, and less power generated from thermal generation in New England and any other location from which NEPOOL would have purchases thermal generation.

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[5] Final Environmental Impact Statement, op. cit., p. 1-5.

COSTS AND NET BENEFITS OF THE PROPOSED SOLUTION

The direct cost to NEPOOL of the Phase II transaction consists of the capital costs, and operating costs of the transmission system expansion required to implement the project. The capital costs which are by far the most significant, include only those for facilities constructed in the New England states; Canadian transmission costs are to be borne by Hydro-Quebec.

The capital costs for the U.S. part of the project are estimated at 547 million dollars. This represents "study-grade" estimates that are considered accurate to only ± 25%. Table 2 shows the present worth of the revenue requirements associated with the base estimate of the cost and with the two extreme values of 25% higher and 25% lower costs, using the assumed base fuel cost trend. Finally, Table 2 shows the net benefits to New England of the Phase II project. The net benefits are positive, ranging from $723 to $1,165 million in present worth of revenue requirements reduction. Similar calculations, for other than the assumed base fuel trends, all showed some advantage of the Phase II project over the gas-turbine alternative, except for one very extreme combination of assumptions involving oil prices escalating 65% less than the base assumption and, at the same time, Phase II capital costs being 25% more than estimated. All other combinations of assumptions produce net benefits ranging from nearly break-even to as much as 1,527 million dollars in present worth of revenue requirements.

The costs of the project to Hydro-Quebec are more difficult to evaluate. This is because Hydro-Quebec considers that most of the system components involved would have been built in any case only a few years later. In 1986, it was estimated that the Phase II project required the "La Grande I" project (1200 MW capacity, with 6,000,000 MWH/year of energy) to be advanced in time from a previously planned year 2000 to 1997. Since then, Hydro Quebec's load growth expectation has increased, and the project may be advanced to an earlier date yet. The DC line from Radisson to Des Cantons is also seen as an acceleration of a line which was originally planned, but as an AC line, for construction in 1994.

TABLE 2

COSTS AND NET BENEFITS OF THE PHASE II PROJECT
(MILLIONS OF 1990 DOLLARS)
Assuming "base" fuel price trends

Gross Savings	Project Costs		Net Benefits
	Capital Costs	P.W. Rev. Req.[a]	
1,849	684 (+25%)	1,126	723
1,849	547 (Base)	901	948
1,849	410 (-25%)	684	1,165

[a] P.W. Rev. Req. = Present worth of revenue requirements.

A comparison by Hydro-Quebec of the-present worth of their total costs, for investments and operation, of all generation and transmission elements affected by the Phase II project, shows:

	COST (Canadian Dollars)
Without the Phase II project:	7,244 million
With the Phase II project:	7,877 million
Increase due to Phase II project:	633 million
Cost increases for other transmission lines:	83 million
For a total additional present worth of:	716 million

The Final Environmental Impact Statement points out that, in addition to the economic benefits that were considered in making the estimates shown here, there are other benefits, not yet quantified, that could be derived from the Phase II facilities. As summarized in the Final Environmental Impact Statements,

"These potential benefits include:

- The opportunity for increased energy banking, whereby NEPOOL members could transmit relatively inexpensive energy north to Quebec and receive equal amounts of energy during on-peak periods when generation costs in New England are much higher. The basic Energy Banking Agreement was established under Phase I, but the amount of energy banking was limited to power levels of 690 MW by the capacity of the Phase I facilities. Construction of the Phase II facilities would raise the potential level of energy banking to almost 2000 MW.
- Additional opportunities for energy interchange, whereby if Hydro-Quebec has additional surpluses of energy, it could sell the surpluses to New England at a fraction of New England's avoided fuel cost.
- Increased ability to make emergency transfers of power to either side of the border for mutual reliability purposes."

INTERREGIONAL IMPACT OF HYDRO-QUEBEC TO NEPOOL TRANSFERS

The large expected imports from Quebec into NEPOOL, New York, and New Brunswick raise the question of what would happen to the Eastern Interconnection if the imports from Quebec were suddenly lost, either from a failure of the Phase II transmission system, or from a collapse (blackout) of the Hydro-Quebec system. Hydro-Quebec could be exporting as much as 3900 MW at one time through its various ties into the Eastern Interconnection areas. However, only some 2000 MW of imports can be lost due to any contingency, because the various systems have agreed on some special operating procedures which are explained in Appendix A. Since NEPOOL, NYPP, PJM, ECAR, and other systems that make up of the Eastern Interconnection are all interconnected and operating in synchronism, serious disturbances could be propagated from one of the systems to its neighbors and even to more distant systems.

The loss of a line or converter carrying 2,000 MW from Quebec to NEPOOL would have the same effect as the loss of a 2,000-MW generating unit in NEPOOL. The largest existing generating units in the northeastern systems are rated at 1,300 MW, and the largest unit in New England is rated at 1,253 MW. Thus, the loss of the Phase II transmission would result in a disturbance much worse than the loss of the largest generator on any system. Similarly, a collapse of the Hydro-Quebec system could cause the sudden loss of all the imports from Quebec to New York, New England, and New Brunswick, except the Phase II imports, totaling as much as 1,900 MW.

When the power supply in New England is suddenly reduced by 2000 MW, this loss is immediately replaced by power generated in New England and in all the areas connected with New England, from the Rocky Mountains and the Gulf Coast to Nova Scotia. Most of this power is generated in areas to the west of New York State and PJM, and passes through these on the way to New England. These large power flows are added to the predominantly eastward economic power flows in the PJM and NYPP areas which are due to the eastern areas' purchases of lower cost power from ECAR and other mid-western areas. The very large combination of these eastward power flows through PJM and NYPP can cause thermal overlook, voltage inadequacies, and possibly instability. These problems are discussed in Appendix B.

In response to these concerns, a study was conducted by the "MEN Study Committee", a group representing PJM, ECAR and NPCC. The latter is the Northeast Power Coordinating Council — representing the New York Power Pool and NEPOOL. The Committee's assignment was to study the impact of the planned increase in imports on the reliability of the regions it represented, including the impact of Hydro-Quebec — NEPOOL transfers on other transfer capabilities. Their review investigated both "steady-state" conditions, i.e. the effect of the loss of the Canadian imports on power flows and voltages in the region, and "dynamic analysis" which concerned any threats to system stability from these contingencies. In both parts, the goal was to determine any limitations on system operation which would be necessary in order to maintain adequate system reliability. The fundamental principle in determining these limitations was that systems outside of NEPOOL should not have to restrict their transfers more severely in contemplation of the loss of Canadian imports to New England than they already do in contemplation of contingencies in their own systems. This principle will be illustrated later in connection with the presentation of the MEN study results.

The MEN studies confirmed that the outage of the Phase II tie, which would interrupt a maximum of 2,000 MW of generation supply to NEPOOL, could cause voltage problems and overloads on heavily loaded circuits in PJM and NYPP. These effects depend on how much power was being transferred from Hydro-Quebec to NEPOOL, and also on how much power was being transferred eastward across PJM and NYPP, before the Phase II tie outage. Therefore, they vary from one time to another. It was found that the pre-contingency conditions governing the effect of Phase II imports on PJM and NYPP transmission can be defined using two key variables:

- The "NYPP Total East Transfers." This is the sum of the west-to-east power flows over 16 transmission lines and transformers that link a "western" and an "eastern" region within the NYPP.
- The "Total ECAR to PJM Transfers." These are the west-to-east power flows over 19 transmission lines and transformers connecting the ECAR and PJM systems.

The potential effects of the Phase II imports on the PJM and NYPP systems were analyzed for peak load times and also for conditions typical of when loads are approximately 75% of peak. The "75% of peak" conditions occur more frequently than peak periods, and can at times involve more serious transmission problems than the peak period; it is therefore important to determine what transfer limitations are needed during "75% of peak" conditions, as well as under peak loading.

Increased power flows generally increase the risk that a given contingency, such as loss of a transmission line, or of a large generator, would cause overloads, voltage inadequacies, or instability. Therefore, each area limits its power transfers to the levels at which these system failures will not occur. For example, the ECAR-to-PJM transfers must be limited to 3950 MW under typical conditions, because with higher transfers certain outages in PJM would result in inadequate voltages within the PJM system. Therefore, the basic principle of the MEN study would require that the loss of the Phase II imports should not cause unacceptable conditions in PJM when the ECAR-PJM transfers are 3950 MW or less.

Interconnected utilities generally make it a practice to restrict their own operations so as not to increase risk and expenses to their neighbors. They do so primarily in recognition of the fact that this mutual cooperation is the only practical way in which the large interconnections of the North American continent can be operated in the long run. This general attitude of cooperation is, to some extent, embodied in formal agreements and rules such as those which govern utilities' membership in the North American Electric Reliability council (NERC) and the various regional reliability councils that make up this organization. The following quotation from the NERC Operating Manual, which sets out basic criteria and rules for interconnected operation, illustrates this approach:

> "When establishing normal and emergency transfer limits, the sending, intervening, and receiving control areas shall consider the effect of power flow through their own and other parallel systems or control areas based on mutually acceptable reliability criteria."

However, the agreements and rules are only the most formal manifestation of the prevailing attitude of utility planners, who understand that mutual respect and consideration are the necessary basis for obtaining the benefits of interconnection, mutual assistance in emergencies, and economic interchange.

The MEN study found that Phase II imports of less than 1500 MW do not require PJM or NYPP to restrict their power transfers more severely than they must do for contingencies in their own system, and that larger imports, up to 2000 MW, would affect PJM restrictions but not those of NYPP. The MEN findings may be summarized by the following table:

	No Phase II Imports	Initial Phase II Loading 1500 MW or less	Initial Phase II Loading 2000 MW
NYPP Total East Transfer Limit - MW	5600(1)	5600(1)	5600(1)
ECAR to PJM Transfer Limit - MW	3950(2)	3950(2)	3250(3)

(1) Based on NYPP internal stability limit
(2) Based on PJM internal steady-state limit
(3) Based on the steady-state impact of the contingency loss of the Phase II tie.

This table indicates that, as mentioned above, if the Phase II imports are limited to 1500 MW, the danger of the loss of the Phase II tie does not require PJM or NYPP to restrict their operation more than they would because of potential contingencies in their own system. However, with 2000 MW of Phase II imports, PJM would have to restrict their imports from ECAR more strictly (3250 MW) than they would need to do in contemplation of a contingency in their system, or risk severe voltage problems in case NEPOOL lost its Phase II imports. Therefore, the Phase II imports may not be increased to 2000 MW unless PJM is importing 3250 MW or less from ECAR.

The table shows that Phase II imports up to 2000 MW do not affect NYPP's ability to transfer power between its western and eastern parts. However, NYPP is investigating ways of increasing their transfer capability. If they do so, the Phase II imports may become a limiting factor, and would then have to be restricted accordingly.

An alternative solution (for which no data are available) would be to install additional transmission facilities on either the PJM or, eventually, NYPP systems. The technical details and costs of such changes have not been determined; and the allocation of any costs would have to be negotiated among the parties involved.

Economic Consequences of Transfer Limitations

In general, it would be most advantageous for NEPOOL to import as much energy as possible to replace its most expensive internal sources, which are in heaviest use during peak load times and when large amounts of low-cost generation are out of service. As was explained earlier, the Phase I and Phase II contracts provide, basically, for the sale of a given amount of energy per year. How much of it can be imported at times when it is most beneficial is limited by the MW capacity of the HVDC tie. The additional transfer limitations further restrict the amount of power that can be imported at certain times, and thus they restrict NEPOOL's ability to optimize the scheduling of imports. Some of the contracted energy imports will have to be taken at times when they replace cheaper energy than they would have if NEPOOL could have scheduled them whenever it wanted to. This will raise NEPOOL's total fuel cost. There is also a secondary effect: since the price of the imported power is a given fraction of NEPOOL's average fuel cost over the previous year, the increase in NEPOOL's total fuel cost (and therefore of its average fuel cost) will increase the price that NEPOOL will have to pay for the imported energy in the next year. An estimate of the effect of these cost increases is not available.

While there have been some considerations of what transmission reinforcements would be necessary to remove existing limitations on the ECAR-to-PJM and NYPP Total East Transfers, both those due to internal limitations and those due to the Canadian imports, the exact nature of these reinforcements, their cost, and the amount by which these limitations would be relieved are not available because studies have been, for the most part, informal and preliminary. The informal general consensus among system planners in the region seems to be that the cost of increasing transfer capabilities by substantial amounts is likely to exceed the economic gain produced by these increases, at the present cost differentials.

CONCLUSION

The "Phase II" power imports agreement is estimated to produce capacity and energy cost benefits with a present worth of 1,849 million dollars, at an estimated cost of 948 million dollars. These benefits will be reduced somewhat by the need to limit the total imports to less than the full capacity of the HVDC ties, whenever importing more would threaten the reliability of systems in New York State or in the Mid-Atlantic (PJM) area.

The Phase II increase of power imports from Quebec to New England face three separate transmission bottlenecks:

1. HVDC ties had to be increased in order to carry the power between the unsynchronized Hydro-Quebec and NEPOOL systems. HVDC transmission lines were extended 700 miles in Quebec and 133 miles in New England.
2. In order to absorb the additional power into the NEPOOL system, additional 345-kV AC transmission had to be extended 51.8 miles in New England.
3. When ECAR-to-PJM transfers are at or near their safe limits, the Canadian imports must be restricted below their maximum capacity in order not to impose additional restrictions on the ECAR and PJM. Similar restrictions related to NYPP west-to-east transfers may become effective in the future.

APPENDIX A

Operating Modes to Reduce Amounts of Contingencies

With the possibility of as much as 3,900 MW being imported into New York, New England and New Brunswick from Quebec through the various DC ties shown in Figure 3, special provisions must be made because a collapse of the Hydro-Quebec transmission system would result in the sudden loss of 3,900 MW to these areas. This condition is unacceptable. Most of the missing 3900 MW would rush in from the rest of the Eastern Interconnection through the three areas' ties to the rest of the United States and Ontario, overloading lines and causing instability in the receiving areas. In order to reduce the maximum amount that can be lost at one time to an acceptable value, it has been agreed to operate the Quebec imports in one of two possible modes:

1. One mode consists of separating the generators supplying the Phase II power from the rest of the Hydro-Quebec system. This is called "isolated Phase II" operation. The Hydro-Quebec system would in effect be split into two parts. One, the Phase II System, would supply no more than 2000 MW to NEPOOL over the Phase II tie. The other, consisting of all the rest of Hydro-Quebec, would be supplying no more than 1900 MW to New York, Vermont, and New Brunswick.

2. The second operating mode, applicable only to periods of lower total imports, may be called the "Phase II tied" mode. It consists of leaving the units serving the Phase II system connected to the rest of the Hydro-Quebec system at Radisson. "Phase II tied" operation is limited to times when the total Hydro-Quebec exports are no more than 2,200 MW, and therefore involves a maximum loss of 2,200 MW to the Eastern Interconnection. This loss, however, would have less serious effects than the 2000-MW loss in "isolated Phase II" operation, because the lost imports would be located in widely separated areas.

The choice of operating mode is fundamentally up to Hydro Quebec, except that the restrictions of 2200 MW of total imports for the "Phase II tied" mode must be adhered to.

APPENDIX B

Cause of Transfer Limitations

System planners and operators are concerned with four types of events which could result in loss of service quality, service interruptions, or possibly, extended area black-outs:

- Overloading of transmission lines in normal service.
- Overloading of lines as a result of a system contingency. When a transmission line fails, power carried on that line immediately starts flowing on other lines linking the same general areas. When a generator fails, the output of that generator is taken up by other generators, resulting in changes in system power flows. These changes may result in overloading some lines after the contingency. In some cases, the overloading, and consequent loss, of some lines may cause the overloading and loss of others, resulting in "cascading outages" and possible area blackouts.
- Voltage on areas of the transmission system may be reduced below acceptable service standards, or may actually collapse in "voltage instability," as a result of the same contingencies mentioned above.
- Short circuits on transmission lines or the sudden loss of major generating sources may result in system instability. In this situation, some generators on the system are accelerated, and others decelerated or accelerated at a different speed, so much that the generators cannot regain their normal synchronism.

Each of these occurrences is generally associated with the transfer of large amounts of power over transmission systems because with larger power flows the system is operating near to its physical limits, and a disturbance is more likely to take it beyond them. The system breakdown can be avoided by limiting the power transfers to given values.

CASE STUDY NUMBER 2
TRANSMISSION TO DELIVER LOW COST POWER TO EL PASO ELECTRIC COMPANY

Presented to the

Office of Technology Assessment
U.S. Congress

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TABLE OF CONTENTS

SUMMARY 1

THE PROBLEM 1

PROPOSED SOLUTION TO PROBLEM 5

COST OF PROPOSED SOLUTION 8

ECONOMIC BENEFITS OF THE ARIZONA INTERCONNECTION PROJECT . . . 9

CASE STUDY NUMBER 2

TRANSMISSION TO DELIVER LOW COST POWER TO EL PASO ELECTRIC COMPANY

SUMMARY

The El Paso Electric Company (EPE) provides electric service to customers in parts of New Mexico and Texas. It is tied through only two EHV lines to other utilities in New Mexico and Arizona, and also maintains one HVDC tie, of limited capacity, to another Texas utility. Because of transmission constraints on its own system and on neighboring systems, EPE must forego the purchase of large quantities of low-cost economy energy available in the Southwest power market and substitute higher cost electricity produced locally with gas- and oil-fired generation. Additionally, the company's load is growing, and it needs to obtain additional generating capacity. Surplus generating capacity is available from other Southwest utilities at a lower cost than EPE could achieve by building new generating facilities. However, an increase in EPE's existing tie-line capacity would be required to deliver this lower cost capacity. A proposed transmission project, the Arizona Interconnection Project, would provide the additional capacity needed in the future, and would also enable the company to import large quantities of low-priced energy to replace higher-cost internal generation.

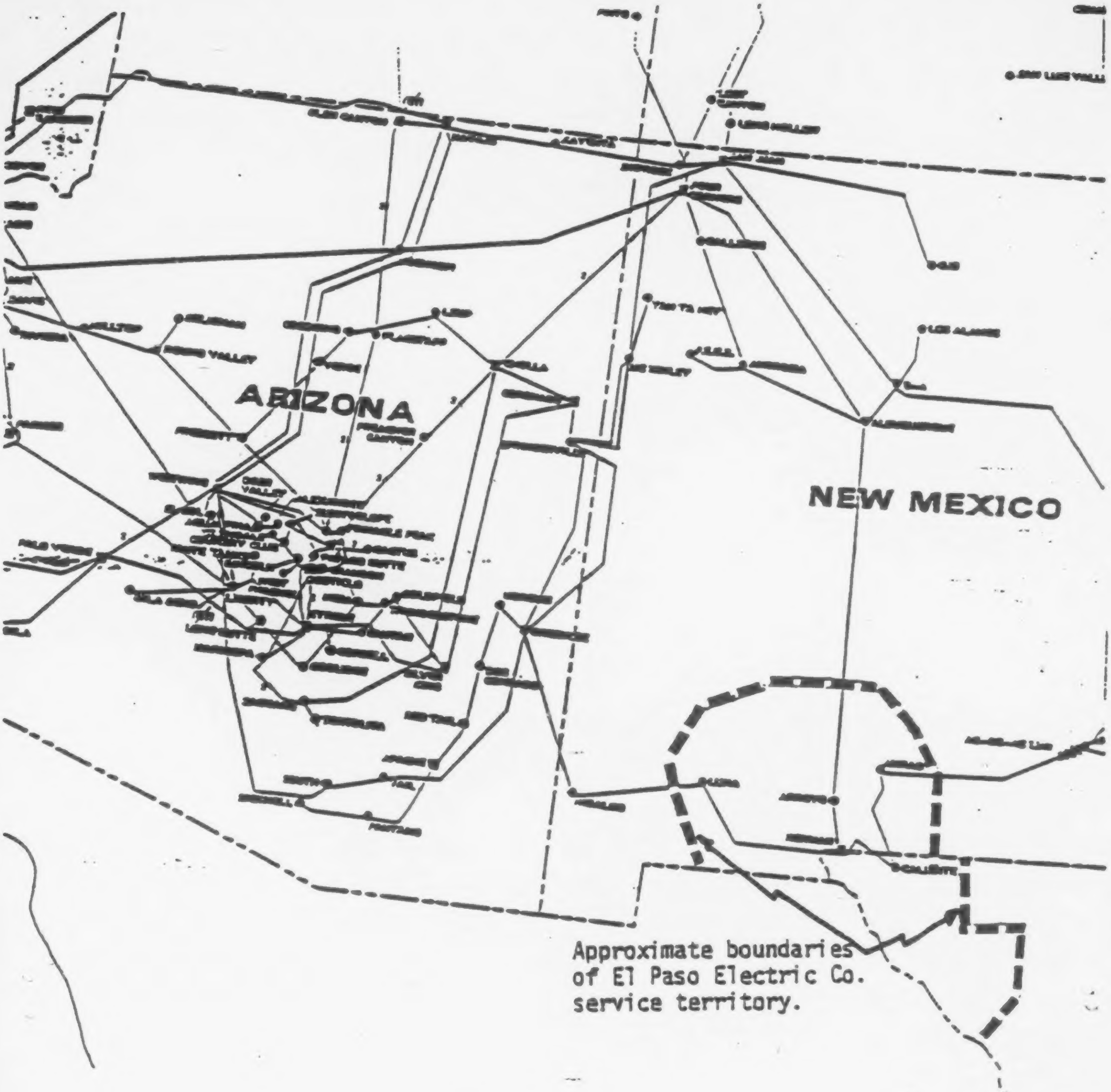
THE PROBLEM

The electric power supply situation in the Southwest is characterized by remotely-sited baseload generation, long transmission lines, and a sparsely developed transmission grid. While low-cost economic power is produced by these large base load facilities, there often are significant distances involved in transmitting this power to load centers. Therefore, it is common for utilities to "back-up" the large low-cost facilities with locally-sited oil-and gas-fired generation. The geographic area served by El Paso Electric Company in southern New Mexico and far western Texas provides an excellent example of both the problems and the benefits associated with adding transmission capability to import lower cost economy energy.

El Paso Electric Company serves 220,000 customers with an annual peak load (in summer) of 938 MW. EPE's service area is geographically located in the southeastern corner of the Western Systems Coordinating Council (WSCC). As Figure 1 illustrates, EPE's primary ties to the rest of WSCC include two 345-kV transmission lines, one connecting to the PNM system in Albuquerque and the other connecting to Tucson Electric Power in Arizona. There is an additional 115-kV tie (not shown on the map) to Albuquerque through the Plains Electric G&T system. EPE also is tied via a 345-kV AC line and a HVDC tie to Southwestern Public Service (SPS) Company in the Southwest Power Pool; however, the capacity of the AC/DC/AC inverter terminal presently limits the amount that can be imported from SPS to 200 MW. In summary, EPE is tied to the rest of the US by only three EHV lines and one 115-kV line.

Although its principal load area is in Texas, EPE has no interconnections with any other Texas utility except for the DC link with SPS. Its most important interconnections are with Arizona and New Mexico utilities only.

EPE's problem is quite simple. Without expanded transmission access to remotely sited economical energy sources, the utility is forced to supply large portions of its native load from high-cost, locally sited, gas- and oil-fired generation. Table 1 summarizes EPE's load and generation resources projected for the years 1990 through 2000. Approximately two-thirds of the utility's total generation resources are gas- and oil-fired generation located near El Paso. While existing transmission ties are marginally sufficient to import EPE's shares of the Four Corners coal plant and Palo Verde Nuclear Units 1 and 2, there are significant opportunities in the Southwestern bulk power market to purchase additional economy energy from other utilities in New Mexico, Arizona, Nevada, and Colorado. EPE decision-makers are convinced that the savings to be obtained from these additional economy energy purchases more than offset the cost of building the transmission required to deliver this energy. Additional savings would result from reductions in the amounts EPE would otherwise pay PNM for wheeling across its system from the Four Corners coal plant or to Arizona utilities for wheeling power from Palo Verde Nuclear Generating Station. Other advantages of expanding EPE's transmission ties to the rest of WSCC include increased reliability and decreased losses.


ARIZONA
NEW MEXICO

Approximate boundaries of El Paso Electric Co. service territory.

Figure 1

El Paso Electric Company
Location and Transmission Ties

TABLE 1

EL PASO ELECTRIC COMPANY

LOADS AND RESOURCES

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
1.0 Generation Resources											
1.1 Rio Grande - Gas & Oil	246	246	246	246	246	246	246	246	246	246	246
1.2 Newman - Gas & Oil	478	478	478	478	478	478	478	478	478	478	478
1.3 Four Corners - Coal	110	110	110	110	110	110	110	110	110	110	110
1.4 Copper - Gas	69	69	69	69	69	69	69	69	69	69	69
1.5 Remote Generation - Nuclear	410	410	410	410	410	410	410	410	410	410	410
Total Generation Resources	1313	1313	1313	1313	1313	1313	1313	1313	1313	1313	1313
2.0 Total Resource Purchs./ (Sales)	-43	-43	-43	-43	-43	-43	-43	-43	-43	-43	-43
3.0 Total Unavailable Resources	106	0	0	0	0	0	0	0	0	0	69
4.0 Net Resources for Demand	1164	1270	1270	1270	1270	1270	1270	1270	1270	1270	1201
5.0 System Demand											
5.1 Native System Demand	918	952	976	1009	1039	1068	1099	1125	1151	1178	1206
5.2 Line Losses	9	9	8	8	8	8	8	8	8	8	8
System Demand	927	961	984	1017	1047	1076	1107	1133	1159	1186	1214
6.0 Firm Sales - TNP Lordsburg	63	68	74	79	75	75	75	75	75	75	75
7.0 Total System Demand	990	1029	1058	1096	1122	1151	1182	1208	1234	1261	1289
8.1 Margin Over Total Demand - MW	174	241	212	174	148	119	88	62	36	9	-88
8.2 Margin Over Total Demand - PCT	18%	23%	20%	16%	13%	10%	7%	5%	3%	1%	-7%
9.0 WSCC Reserve Requirements											
9.1 Largest Hazard	213	213	213	213	213	213	213	213	213	213	213
9.2 5% of Total Demand	50	51	53	55	56	58	59	60	62	63	64
Total Reserve Requirements	263	264	266	268	269	271	272	273	275	276	277
10.0 Margin Over Reserve Req. MW	-89	-23	-54	-94	-121	-152	-184	-211	-239	-267	-365

Note:
A. The data shown is for planning purposes only.
B. Line 1.5 remote generation represents Palo Verde (400 MW) and Four Corners (110 MW) adjusted for Imperial Irrigation District (IID) sale (100 MW).

Source: El Paso Electric Company

At present, EPE's total net tie line transmission capability is estimated at 400 to 500 MW. However, projections by EPE planners show that additional generation resources will be needed by the year 1990 to satisfy the WSCC requirements for adequate reserve capacity. EPE estimates that approximately 152 MW of additional capability will be needed by the year 1995, and would be best provided from remote generation resources, such as the Palo Verde nuclear plant in Arizona and the San Juan coal plant in northwestern New Mexico. This would require a corresponding increase in transmission capacity. More importantly, the existing transmission system forces EPE to forego the purchase of significant amounts of economy energy from remote sources. The amount of economy energy that would be available but undeliverable (to EPE) due to transmission constraints is projected at 500 Gigawatt-hours(GWH) in 1990, but is expected to increase by the year 2000 to a level between 1200 and 2500 GWH. The savings associated with purchasing this economy energy provide the primary incentive for building a new transmission line called the Arizona Interconnection Project (AIP), which is described further in the following section.

PROPOSED SOLUTION TO PROBLEM

El Paso Electric Company proposes to provide the additional transmission capacity needed to import low-cost economy energy and additional generating capacity from Arizona and northern New Mexico by building a new transmission line, to be called the Arizona Interconnection Project, which is described as follows:

> "El Paso Electric Company (EPE) is proposing to construct approximately 210 miles of single circuit 345-kilovolt (kV) transmission line between the existing Springerville switchyard near Springerville, Arizona and a Luna substation near Denning, New Mexico. The line, known as the Arizona Interconnection Project, would be constructed using wood H-frame structures approximately 75 feet in height. The project would also require additions to the Luna sub-station, jointly owned by EPE, Public Service of New Mexico (PNM), and Texas-New Mexico Power (TNP), and the Springerville switchyard, owned and operated by Tucson Electric Power (TEP)."[1]

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[1] Excerpt from Arizona Interconnection Project, proposed plan amendment and final *EIS*, Prepared by the US Department of Interior, Bureau of Land Management, Las Cruces District Office, New Mexico, March 1, 1987.

The proposed transmission line would interconnect with the existing Arizona and New Mexico transmission systems as shown in Figure 2. According to EPE estimates, the addition of the AIP line would increase EPE's net tie-line capacity of 400 to 500 MW by an additional 400 MW.

During hearings before the New Mexico Public Service Commission (NMPSC) regarding EPE's request for a Certificate of Convenience and Need (CCN) to build the AIP, an alternative solution was proposed. Specifically, it was suggested that an additional 345-kV line from Greenlee to Luna (as illustrated in Figure 2) would be sufficient. According to supporters of the alternative, a second Greenlee to Luna line would cost only a third to a half as much as the Springerville to Luna alternative. The Greenlee to Luna line would be considerably shorter in length, and there would be no need for the series capacitors that are required for the Springerville to Luna line.

El Paso Electric Company opposed the Greenlee to Luna alternative, contending that, if the Greenlee to Luna line were built, an additional transmission line would also have to be built between Springerville and Greenlee. The cost of this additional line would be approximately 40 million dollars. When added to the cost of the Greenlee to Luna line, the total cost would come to 75 million dollars, versus 70 million dollars estimated for the AIP line. In addition, El Paso Electric cited the following reasons for selecting the Springerville to Luna alternative:

- The Arizona Interconnection Project offers higher reliability than that of the Greenlee to Luna alternative. Reliability of service to New Mexico is improved because the Springerville station is a strong source and an approved exehange point for Palo Verde power. The AIP alternative is further preferable from a reliability standpoint because it provides transmission over a path that is physically separate from other existing transmission rights-of-way.
- The AIP results in larger total import capability for the entire state of New Mexico. Specifically, the total New Mexico import capability with the AIP line would be 2205 MW versus 2068 MW for the Greenlee-Luna alternative.

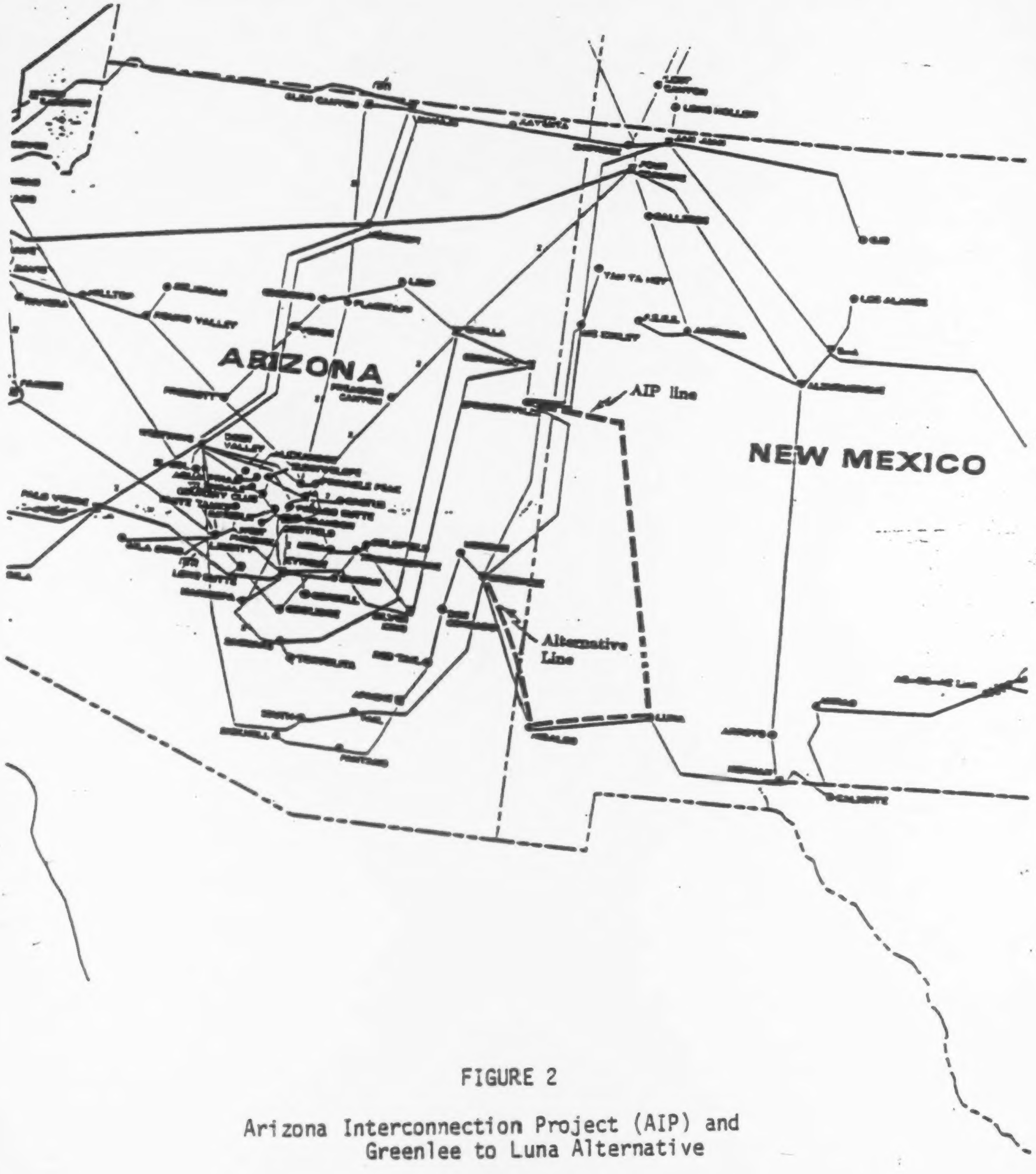
ARIZONA
NEW MEXICO
AIP line
Alternative Line
LUNA

FIGURE 2

Arizona Interconnection Project (AIP) and Greenlee to Luna Alternative

- The AIP offers better voltage performance in southern New Mexico. In comparing the two alternatives, it was found that the AIP option resulted in New Mexico voltages which were approximately two percent higher than the Greenlee-to-Luna alternative. This is especially important since import capability along that corridor is currently voltage limited.
- The AIP offers lower system losses than the suggested alternative for the entire New Mexico system. Specifically, total New Mexico transmission losses are approximately 92 MW with the AIP versus 103 MW with the Greenlee-to-Luna alternative.

For all of the above reasons, EPE continued to recommend the Springerville to Luna transmission line, known as the Arizona Interconnection Project to accomplish the needed transmission system upgrade. The New Mexico PSC subsequently concurred and in 1987 granted EPE's request for a CCN to build the proposed AIP line from Springerville to Luna.

COST OF PROPOSED SOLUTION

According to current estimates, the total AIP project cost will be 78.7 million dollars, based on the following cost breakdowns:

• Capital costs of transmission lines in substations	65 million dollars.
• Right-of-way acquisition costs	5 million dollars.
• Allowance for funds used during construction (AFUDC)	8.7 million dollars.

(Based on an assumed interest rate of 11.5%.)

assumption[3]). EPE also estimates that approximately 58 million dollars would be saved in avoided wheeling costs over the next ten years as a result of the operation of the AIP. More specifically, according to F.E. Mattson of EPE:

> "The AIP will allow EPE to avoid paying wheeling charges to other electric utilities and will lower system transmission losses. For example, Public Service Company of New Mexico's transmission wheeling rate is now $3/kW-month, which would amount to $3,600,000 annually for 100 MW of capacity without the AIP. In addition, without the AIP the Tucson Exchange Agreement would have to be renegotiated, which could require EPE to pay several million dollars per year to the Arizona utilities for Palo Verde wheeling."[4]

The economic analysis performed by EPE assumes that the AIP would permit increased economy energy purchases and associated production cost savings under two purchase assumptions. The first assumption is that 400 MW of additional economy energy could be imported; the second assumption is that only half this amount could be imported. Economic scenarios representing these two assumptions were compared with a base scenario in which it was assumed the AIP would not be built. The amounts of power imported from EPE's portions of the Palo Verde and Four Corners units remained the same in all three scenarios. The two assumptions regarding the amount of additional economy energy only affected the time to economic breakeven by a few months. However, the present worth of cumulative net savings increased from 108 to 164 million dollars when the additional economy purchases were increased from 200 MW to 400 MW, respectively.

In summary, EPE continues to believe that the benefits of the AIP to its customers and to other New Mexico rate-payers will far outweigh the costs of the project. EPE commenced its active pursuit of the AIP line in 1982. An Environmental Impact Statement (EIS) was prepared by the Bureau of Land Management in 1986, and the present line routing was approved in Spring of 1987. Request for a CCN for the line was made to the New Mexico PSC in 1986 and granted in Summer of 1987. At the present time, line construction is underway, and the line is projected to be in service by November of 1989.

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[3] Under "split savings" pricing, the total production cost savings associated with an economy energy transaction are split equally between buyer and seller. The price is set at the seller's incremental cost plus 50% of the savings, or equivalently at the buyer's decremental cost less 50% of the savings.

4. Rebuttal Testimony filed on behalf of EPE by G.E. Mattson (Docket No. 2044).

Power Technologies, Inc.

TECHNOLOGICAL CONSIDERATIONS IN PROPOSED SCENARIOS FOR INCREASING COMPETITION IN THE ELECTRIC UTILITY INDUSTRY

R17A-88

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TABLE OF CONTENTS

TABLE OF CONTENTS

PAGE

PREFACE

CHAPTER 1 - INTRODUCTION AND PROPOSED SCENARIOS 1-1

1.1 INTRODUCTION 1-1

1.2 SCENARIO DESCRIPTIONS 1-2

1.2.1 Scenario 1 - Strengthening the Existing Regulatory - Utility Bargain 1-3
1.2.2 Scenario 2 - Expanding Transmission Access in the Existing Institutional Structure 1-5
1.2.3 Scenario 3 - Competition for New Bulk Power Supplies 1-6
1.2.4 Scenario 4 - All Source Competition for All Bulk Power Supplies with Generation Segregated from Transmission and Distribution Services 1-8
1.2.5 Scenario 5 - Common Carrier Transmission Services In a Desegregated, Market-Oriented Electric Power Industry 1-11

1.3 INDUSTRY STRUCTURE AND TECHNICAL RESPONSIBILITIES . . . 1-13

1.3.1 Physical Limitations 1-17
1.3.2 Industry Structure and Institutional Relationships 1-17

1.4 TECHNICAL PROBLEMS POSED BY SCENARIOS 1-19

CHAPTER 2 - NEW GENERATION SOURCES 2-1

2.1 ACCOMMODATION OF NEW SOURCES UNDER EACH SCENARIO . 2-1

2.1.1 Comments on Scenario 1 - New Sources and Related Technical Problem Areas 2-1
2.1.2 Scenario 2 2-2
2.1.3 Scenario 3 2-2
2.1.4 Scenario 4 2-4
2.1.5 Scenario 5 2-7

TABLE OF CONTENTS (continued)

PAGE

2.2 SIGNIFICANT SUPPLY CHARACTERISTICS 2-7

2.2.1 Heat Rates and Control Ranges 2-10
2.2.2 Maintenance and Unavailability Characteristics 2-12
2.2.3 Unit Response Rates 2-13
2.2.4 Fuel and Environmental Considerations 2-17
2.2.5 Lead Time Requirements 2-18
2.2.6 Long Term Availability of New Sources 2-19
2.2.7 Plant Location and Transmission Access 2-20

2.3 CONTRACTUAL ARRANGEMENTS WITH NEW GENERATION SOURCES AND EFFECTS ON SYSTEM OPERATION AND ENGINEERING 2-20

2.3.1 Scheduling and Dispatchability 2-21
2.3.2 AGC System Control of Generation 2-23
2.3.3 Economic Structure for Operating Controls 2-24
2.3.4 Contract Provisions for Coordination of Bulk Power System Planning 2-25
2.3.5 Contract Provisions For Resolution of System Engineering And Operating Technical Problems 2-26

2.4 TECHNICAL PROBLEMS AND POSSIBLE SOLUTIONS 2-27

2.4.1 Technical Problems in New Source Generation Scheduling 2-27
2.4.2 Generation Dispatch and Load Following 2-29
2.4.3 AGC Systems 2-30
2.4.4 Generation Planning and Capacity Reserves 2-31
2.4.5 Solution of System Engineering Problems 2-32

2.5 TECHNICAL ANALYTICAL ISSUES 2-33

2.5.1 Security Based Dispatch 2-33
2.5.2 Overall Economic Effects 2-34
2.5.3 Unit Commitment Scheduling 2-34
2.5.4 Economic Framework for Non-Traditional Generation Services 2-34
2.5.5 AGC System Design 2-35

TABLE OF CONTENTS (continued)

PAGE

CHAPTER 3 - INCREASED TRANSMISSION ACCESS AND WHEELING . 3-1

3.1 WHEELING AS AN ISSUE 3-1

3.1.1 Wheeling Practices 3-2
3.1.2 Difference between Supplied and Delivered Power 3-4
3.1.3 Possible Problems and Solutions 3-5

3.2 POSSIBLE EFFECTS OF CONTRACTUAL ARRANGEMENTS 3-5

3.2.1 Money Wheeling 3-5
3.2.2 Loop Flows 3-6
3.2.3 Contract Types 3-9
3.2.4 Effects on Operations 3-11
3.2.5 Contractual Effects on System Evolution 3-12

3.3 POSSIBLE OPERATIONAL AND PLANNING PROBLEMS 3-13

3.3.1 Real-Time Control 3-13
3.3.2 Scheduling Problems 3-16
3.3.3 Maximizing Network Use 3-17
3.3.4 Transmission Planning Problems 3-19
3.3.5 Solving System-Engineering Problems 3-20
3.3.6 Emergencies 3-22

3.4 ANALYTICAL PROBLEMS 3-24

3.4.1 Definition of Available Transmission Capacity 3-24
3.4.2 Reliability and Security Issues 3-27
3.4.3 The Transmission Scheduling Problem 3-27
3.4.4 Costing, Valuing, and Pricing 3-29

CHAPTER 4 - SUMMARY OF TECHNICAL ISSUES AND POSSIBLE SOLUTIONS 4-1

4.1 SUMMARY OF TECHNICAL PROBLEMS POSED BY SCENARIOS . . 4-1

4.2 MEASURING TRANSMISSION SYSTEM CAPABILITY 4-2

TABLE OF CONTENTS (continued)

PAGE

4.3 SPINNING RESERVES AND UNIT COMMITMENT 4-3

4.4 AGC SYSTEMS AND FREQUENCY CONTROL 4-4

4.5 SCHEDULING TRANSMISSION SYSTEM USE 4-7

4.6 BULK POWER SYSTEM PLANNING PROBLEMS 4-9

4.7 PROBLEMS RELATED TO DISPATCHING 4-10

4.8 SOLUTION OF SYSTEM-WIDE PROBLEMS 4-12

PREFACE

PREFACE

This report is one of two submitted to the Office of Technology Assessment of the U.S. Congress (OTA) by Power Technologies, Inc. (PTI) as part of the effort of OTA to provide information to the Congress in the potential restructuring of the electric utility industry.

This report deals with the technological background of the industry in the U.S. The companion report, "Technical Background and Considerations in Proposed Increased Wheeling, Transmission Access and Non-Utility Generation," discusses the general technical aspects of the electric utility industry and those technical issues specifically related to increased transmission access, wheeling, and non-utility generation. A number of unresolved technological issues are set forth in this report.

The authors wish to express their appreciation to the various engineers in the industry who have been kind enough to supply data for these reports and who have reviewed the drafts of the texts. Specifically, we wish to thank the American Electric Power Service Corporation, the staff of the North American Reliability Council (NERC), various members of the NERC Operating Committee and the Electric Power Research Institute (EPRI.)

CHAPTER I

CHAPTER 1
INTRODUCTION AND PROPOSED SCENARIOS

1.1 INTRODUCTION

This report extends discussions contained in the report submitted to OTA, "Technical Background and Considerations in Proposed Increased Wheeling, Transmission Access and Non-utility Generation."

The current report presents five scenarios developed as a result of a workshop sponsored by OTA in the fall of 1987, summarizes the expected industry structure under each, explores major technical problems, and discusses possible solutions.

This chapter describes the five suggested scenarios, postulates resulting industry structures that would satisfy the conditions of each scenario, and outlines the significant technical problem areas resulting. In the scenarios which depart the most from existing industry structure, the industry structure affects the feasible solution mechanisms to some of the technical problems. As each successive scenario assumes more competitive forces in the industry, the existing vertically integrated utility begins to disappear from the scene. The responsibilities and functions necessary to make the utility subsystems and interconnected power systems function properly in a technical sense are assigned to the successor entities. The broad classes of technical problem areas of concern are those raised by new generation sources and those associated with the transmission systems. These are discussed in the second and third chapters, respectively. The fourth chapter summarizes the technical issues and possible solutions.

The technical problems associated with dispersed generation sources (DSGs) which are connected to the distribution systems are independent of the structure of the industry for all practical purposes and are not treated in any depth in this report. The previous OTA report, cited above, summarizes the technical problems associated with these smaller, dispersed non-utility sources connected to the distribution system. The technical problems raised by the five scenarios that are discussed are primarily associated with bulk power systems, generation, and transmission systems.

Throughout these reports the terms "wheeling", "wholesale wheeling" and "retail wheeling" are used. The definition of wheeling used is that given in the glossary appended to the recent report "Some Economic Principles For Pricing Wheeling" issued by the National Regulatory Research Institute:

> "Wheeling - The use of the transmission facilities of one system to transmit power of and for another entity or entities."

The two subclasses of wheeling are defined as shown below:

> Wholesale Wheeling - The wheeling of power for delivery to a utility system.
>
> Retail Wheeling - The wheeling of power for delivery to a retail customer.

1.2 SCENARIO DESCRIPTIONS

Five alternative scenarios were developed as a consequence of the OTA Workshop held in the fall of 1987, and are described below. Each scenario description outlines the industry structure envisioned, the regulatory structure, the degree of transmission access, the modes for accomplishing system operating and planning functions and suggested pricing mechanisms. Possible industry structures under each future are discussed in section 1.3 in order to define terms and to further specify the structure in the scenarios which are the most divergent from the current structure.

1.2.1 Scenario 1 - Strengthening the Existing Regulatory - Utility Bargain

Scenario 1 continues the existing regulatory scheme and electric power industry structure and reaffirms the regulatory-utility bargain. Minor modifications of regulatory rules and procedures improve the ability of utilities to attract capital for construction of new facilities and to assure a reasonable return to investors (e.g., "rolling prudence reviews"). Modifications of PURPA rules to correct perceived imbalances in avoided cost pricing rules for QF power are also allowed. Many utilities continue to rely on QFs and IPPs for a portion of new power needs. Transmission access remains on a voluntary basis to be negotiated between the participants. FERC retains its authority over transmission rates and wholesale power sales.

Industry structure:
There is a mix of vertically-integrated utilities; investor-owned utilities; public power, cooperatives, and federal power authorities; self-generators; qualifying facilities (QFs), and independent power producers (IPPs). Trends of internal realignments and restructurings and mergers and acquisitions continue within limits of existing laws.

Regulatory structure:
The existing federal and state regulatory scheme continues, with no changes in PURPA, FPA, PUHCA. Minor modifications/adjustments are made as noted above.

Transmission Access:
Utilities may provide access voluntarily for wholesale and retail customers. No new NRC wheeling orders as part of new nuclear plant approvals are likely, since there are no new nuclear plants. Stringent standards for FERC wheeling orders also likely to preclude mandatory wheeling. States have limited jurisdiction.

System Operation:

System reliability and coordination is maintained by the local utility control center. For non-utility power supplies, operational responsibilities are based on contract terms with the local utility.

Dispatch (maintenance, unit loading) is determined by the local utility (perhaps under a power pool agreement) for utility owned or leased units. For QFs and IPPs, dispatch depends on contract terms with the local utility.
Emergency curtailments are allocated according to state-regulated curtailment policies.

Planning and Developing Resource Additions:

Generating capacity: Utilities develop capacity expansion plans with state regulatory oversight. QFs are assured market for their power under the state's implementation of PURPA and are a component of the expansion plan. IPPs may be included in the expansion plan as determined by the utility and state regulators. QFs, IPPs, and self-generators plan and build capacity based on their own perceptions of need and profitability.

Transmission additions are developed by local utilities subject to regulatory approval. Some non-utility entities may build private transmission lines, but have no eminent domain authority and uncertain regulatory status.

Distribution additions are the responsibility of local utilities with regulatory approval.

Conservation and load management programs are developed by local utilities with regulatory approval.

Pricing:

Prices are set by utilities in regulatory proceedings. Most retail services are bundled, but states allow utilities to offer special rates based on different reliability levels and services to large retail customers in response to competitive pressures. Transmission prices are regulated by FERC. States have limited jurisdiction over transmission.

1.2.2 Scenario 2 - Expanding Transmission Access in the Existing Institutional Structure

Scenario 2 is intended to increase both the number of bulk power sellers and the number of potential bulk power buyers by 1) removing some of the size, technology, fuel, and ownership limitations for qualifying facilities through legislative modifications to PURPA and the Public Utility Holding Company Act; and 2) changing the mandatory transmission access provisions of the Federal Power Act to a broader public interest standard to make utilities and large retail customers eligible to apply for mandatory wheeling orders. Policies intended to encourage bulk power sales and wheeling are continued and expanded.

Industry structure:
The existing mix of utilities, self-generators, cogenerators, independent power producers continues. Unregulated utility subsidiaries or affiliates increase participation in bulk power supply. Current trends of restructuring, mergers and acquisitions continue.

Regulatory structure:
The existing federal-state regulatory scheme continues, with wider eligibility for QFs under PURPA and broader FERC authority for issuing mandatory wheeling orders for utilities and large retail customers.

Transmission access:
Utilities and large retail customers can petition FERC for mandatory wheeling orders to non-local generators based on a new public interest standard.

System Operation:

System reliability and coordination is maintained as in Scenario 1.

Dispatch (maintenance, unit loading) is the same as in Scenario 1, with the following exception. For transmission accessors not subject to utility control, loading and dispatchability are determined by contracts between generator and consumer.

Emergency curtailments are allocated according to state regulated curtailment policies, as in Scenario 1. For outages of non-utility or wheeled power, curtailment and backup power are based on standby service contracts with the local utility.

Planning and Developing Resource Additions:

Generating capacity: Same as in Scenario 1, with one addition. IPPs (as well as QFs) are assured a market for their power under the state's implementation of PURPA and are a component of the capacity expansion plan.

Transmission additions: Same as in Scenario 1, with the following exception. States may require that utilities include provisions for adequate transmission capacity for wheeling services in system planning.

Distribution additions: Same as in Scenario 1.

Conservation and load management: Same as Scenario 1.

Pricing:

The existing structure of price and service regulation is largely left undisturbed. Prices paid to power suppliers under PURPA are based on states' avoided cost rules. This includes use of bidding systems by some states. Transmission services and pricing are established by contract negotiation under FERC jurisdiction.

1.2.3 Scenario 3 - Competition for New Bulk Power Supplies

Scenario 3 establishes an institutional structure to allow all source competition for new bulk power supplies with market based pricing. The scenario is loosely based on the Keystone and Hesse proposals. Transmission access is included as a prerequisite for participation in the competitive system. Mandatory transmission access under the public interest standard of Scenario 2 is also available for bulk power transactions by utilities. Provision of wheeling services to retail customers remains voluntary. Utilities are able to participate in "bidding" for new capacity within their own service territories and those of other utilities with appropriate safeguards to limit problems of self-dealing, conflict of interest, etc. Scenario 3 creates a two-tiered bulk power supply system. New power is supplied under a minimally regulated, "workably-competitive" market with existing generation remaining under the current state-federal scheme of regulated entry and pricing. The electric power supply industry gradually evolves to an all-competitive generating sector as existing plants are replaced.

Transmission and distribution services remain highly regulated.

Industry structure:

The existing mix of utilities, self-generators, cogenerators, independent power producers is expanded by entry of unregulated utility subsidiaries/divisions/spinoffs created to build and operate new generating facilities and to sell power in competitive market and other new entrants made eligible by modification of PURPA QF requirements and changes to the PUHCA.

Regulatory structure:

The underlying federal-state public utility regulatory scheme is maintained but entry and pricing regulation for new power supplies is replaced by all source competition. The generating sector gradually is transformed to an all-competitive system as existing capacity is phased out. Transmission and distribution remain highly regulated.

Transmission access:

Three mechanisms exist for provision of transmission services: 1) voluntary transmission agreements for utilities and retail customers; 2) transmission access for new power supplies is assured as a precondition for utility participation in the competitive bidding system; and 3) mandatory "public interest" transmission orders are available from FERC for utilities, but not for retail customers.

System Operation:

System reliability and coordination is maintained as in Scenarios 1 and 2.

Dispatch (maintenance unit loading) is the same as in Scenario 2.

Emergency curtailments are the same as in Scenarios 1 and 2.

Planning and Developing Resource Additions:

Generating Capacity: Same as in Scenario 2 with the following exception. The states are required to use competitive bidding including consideration of non-price factors in selecting new power supplies.

Transmission additions: As in Scenario 2, the public utility transmission company/division plans and constructs transmission capacity with review and approval of regulatory authorities. State rules may require utilities to plan for adequate capacity for instate wheeling of new power supplies and to consider regional transmission needs.

Distribution additions: Same as in Scenarios 1 and 2.

Conservation and load management: Same as in Scenarios 1 and 2.

Pricing:

"Old" power supplies remain under existing price regulation. Prices for new power supplies are market based, set by competitive auction or negotiation. New power supply prices can reflect level of service and other non-price factors. Greater reliance on transmission services may increase pressure for transmission pricing based on actual cost of service with allowances for non-price factors. Transmission prices are regulated by FERC.

1.2.4 Scenario 4 - All Source Competition for All Bulk Power Supplies with Generation Segregated from Transmission and Distribution Services

Scenario 4 creates a competitive system for electric power supplies. Existing and new sources compete to sell power to regulated transmission and distribution companies. Integrated utilities are required to segregate generation activities both institutionally and operationally from transmission and distribution, through creation of separate divisions, subsidiaries or spinoffs. Transmission and distribution activities are heavily regulated. Modifications to PURPA QF requirements and PUHCA restrictions allow broad participation in generation markets. Local distribution companies are primarily responsible for securing adequate power supplies from competing suppliers. Transmission divisions or subsidiary companies provide wheeling services for utilities under regulated rate schedules and can also act as power brokers linking local distribution companies with power suppliers. Distribution companies can obtain mandatory transmission orders from FERC on a public interest standard. There is no mandatory wheeling for retail customers, though it is expected that generators and transmission companies would engage in direct sales to large retail customers on a voluntary basis with bypass or standby payments to local distribution companies.

Industry structure:

Vertical integration of industry is reduced by separation of utility generating segments from transmission and distribution segments. Segregated utility generators, QFs, and IPPs compete to provide power supplies to transmission-distribution and local distribution companies. Some transmission companies also act as power brokers. Industry structure is similar to that of natural gas industry.

Regulatory structure:

Price and entry regulation for electric power supply is replaced with a competitive market. States regulate distribution companies and retail sales. There is mixed federal and state regulation of transmission capacity and services. Under this scenario there is the potential for increased federal regulation and oversight of power sales and formerly intra-system transmission arrangements. However, implementing legislation could provide for a more balanced federal-state division of regulatory authority to give states greater control over intra-state activities.

Transmission access:

With FERC endorsement, states make nondiscriminatory access to transmission services a precondition for existing regulated generation, transmission, and distribution companies to participate in the new competitive system. FERC has authority to order wheeling for customer utilities on a public interest standard. Transmission access for retail customers is provided on a voluntary basis.

System Operation:

System reliability and coordination is maintained by the regulated transmission company or transmission-distribution company. Operational responsibilities of power suppliers and the local distribution companies are specified in contracts.

Dispatch (maintenance, unit loading) are determined by various contracts between power suppliers and either: 1) the regulated transmission companies; 2) the regulated distribution companies; or 3) retail customers.

Emergency curtailments for retail customers served by local distribution companies are allocated according to state regulated curtailment policies. For other customers, curtailments are specified in contracts with the transmission and generation suppliers.

Planning and Developing Resource Additions:

Generating capacity: Electric supply requirements are determined through local distribution company planning processes with state oversight. Competition for supply contracts is open to all generating sources, as in Scenario 3. Transmission utilities may contract for generating capacity to allow them to serve as power brokers subject to state and federal regulation.

Transmission additions: The regulated transmission or transmission-distribution companies have the obligation to provide transmission capacity necessary to support wheeling needs for instate utilities. States may require transmission capacity planning to include consideration and coordination of regional transmission system needs.

Distribution additions: Same as in Scenarios 1, 2, and 3.

Conservation and load management: Conservation and load management programs are provided by local distribution companies, possibly in conjunction with transmission companies.

Pricing:

Bulk power sales are set through competitive markets. Transmission services are regulated by state and federal authorities. Power purchases by distribution companies and retail rates are regulated as now by state authorities.

1.2.5 Scenario 5 - Common Carrier Transmission Services in a Desegregated, Market-Oriented Electric Power Industry

The electric power industry is divided into institutionally separate generation, transmission, and retail distribution segments. The major difference between this scenario and Scenario 4 is that separate transmission companies are explicitly required to provide transmission services as common carriers--i.e. nondiscriminatory service based on approved wheeling tariffs--to all parties requesting service. The transmission company would have an obligation to provide adequate transmission capacity wherever it was technically feasible. Requirements for new transmission capacity would be based upon technical and economic feasibility.* Retail customers have access to transmission services. Distribution and transmission services remain tightly regulated, but in the electric generation segment, market entry and bulk power pricing are primarily left to market forces. Federal and state policies might encourage greater aggregation in transmission services to create coordinated large regional transmission systems - either through mergers and acquisitions or through operational agreements among neighboring systems.

Industry structure:
The competitive generation segment includes formerly-regulated utility generation operations, QFs, and IPPs. Regulated transmission systems are operated as common carriers. Regulated local distribution companies provide retail services.

Regulatory structure:
The generation segment is subject to minimal regulation to assure existence of workably competitive markets. The transmission segment is regulated as a common carrier by federal and state governments. Local distribution companies are regulated by state authorities.

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* Note that these underlined phrases were added to the original scenario description to restrict the implied obligations of a "common carrier" power transmission company to levels applied to other common carrier companies (i.e., gas pipelines, railroads, airlines, etc.).

Transmission access:

Common carrier transmission access - services available on nondiscriminatory basis to wholesale and retail customers. Wheeling customers could contract for different levels of service.

System Operation:

System reliability and coordination is maintained by the separate, regulated transmission company. Operational responsibilities of power suppliers and the local distribution are specified by contracts between them and the transmission company.

Dispatch (maintenance, unit loading) is determined as in Scenario 4.

Emergency curtailments are allocated as in Scenario 4.

Planning and Developing Resource Additions:

Generating capacity: Same as in Scenario 4.

Transmission additions: The transmission utility has an obligation to provide an adequate and reliable transmission capacity necessary to supply the wheeling needs of anticipated customers. Regulatory authorities may require consideration/coordination of regional transmission capacity needs.

Distribution additions: Same as in Scenarios 1, 2, 3, and 4.

Conservation and load management: Same as in Scenario 4.

Pricing:

Bulk power sales are set through competitive markets. Transmission services are regulated by state and federal authorities on a common carrier basis. Transmission rates include adequate signals to assure construction of new transmission facilities. Power purchases by distribution companies and retail rates are regulated, as now, by state authorities.

1.3 INDUSTRY STRUCTURE AND TECHNICAL RESPONSIBILITIES

Table 1.1 summarizes the organizational components in the industry structure postulated in each scenario. The technical function responsibility assignments to the various entities stated in the previous descriptions are also indicated in this table. The regulatory and pricing issues in the detailed descriptions in the previous subsections are not included in the table. They are obviously important attributes, but they affect the major technical problems only indirectly.

Several abbreviations are used in the table and throughout this report to denote successor organizations to the disaggregated operations of existing, vertically integrated electric utilities. These are:

DISCO - the distribution company,
GENCO - the generation company,
TRANSCO - the transmission company, and
T&D Co. - a combination of the TRANSCO and DISCO.

It is not intended that these abbreviations refer to any existing or planned company specifically.

SCENARIO	INDUSTRY STRUCTURE	DISTRIBUTION	COMMENTS
1. STRENGTHENING THE EXISTING REGULATORY - UTILITY BARGAIN.	VERTICALLY INTEGRATED INDUSTRY WITH CURRENT STRUCTURE OF QF'S AND IPP'S.	REMAINS LOCAL UTILITY RESPONSIBILITY.	ESSENTIALLY A CONTINUATION OF CURRENT INDUSTRY STRUCTURE AND TRENDS WITHOUT MANDATORY TRANSMISSION ACCESS.
2. EXPANDING TRANSMISSION ACCESS IN THE EXISTING INSTITUTIONAL STRUCTURE.	EXISTING STRUCTURE SIMILAR TO 1.	SAME AS 1.	CONTINUATION OF CURRENT STRUCTURE WITH ADDITION OF MANDATORY WHEELING PROVISIONS FOR UTILITIES AND LARGE CUSTOMERS.
3. COMPETITION FOR NEW BULK POWER SUPPLIES.	EXISTING STRUCTURE AUGMENTED BY ENTRY OF UNREGULATED GENCO'S (UTILITY SUBSIDIARIES) TO COMPETE FOR NEW GENERATION CONTRACTS WITH QF'S AND IPP'S.	SAME AS 1.	EXPANDS INDUSTRY STRUCTURE BY ALLOWING UNREGULATED UTILITY SUBSIDIARIES TO BID ON NEW GENERATION. OPENS NEW GENERATION TO COMPETITION.
4. ALL SOURCE COMPETITION FOR ALL BULK POWER SUPPLIES WITH GENERATION SEGREGATED FROM TRANSMISSION AND DISTRIBUTION SERVICES.	VERTICALLY INTEGRATED UTILITY STRUCTURE DISAGGREGATION TO FORM GENCO AND COMBINATION TRANSCO+DISC (T&D). STRUCTURE LIKE CURRENT NATURAL GAS INDUSTRY. QF'S AND IPP'S PARTICIPATE IN GENERATION COMPETITION.	SAME AS 3 PLUS TRANSCO'S MAY PARTICIPATE IN LOAD MANAGEMENT AND CONSERVATION.	EXTENDS 3 TO PROVIDE COMPETITION FOR BOTH OLD AND NEW GENERATION. STRUCTURE CHANGE REMOVES GENERATION FROM UTILITIES. REGULATED TRANSCO'S SIMILAR TO NATURAL GAS PIPELINE COMPANIES.
5. COMMON CARRIER TRANSMISSION SERVICES IN A DESEGREGATED - MARKET ORIENTED ELECTRIC POWER INDUSTRY.	COMPLETE DISAGGREGATION OF UTILITI INTO GENCO'S, DISCO'S AND TRANSCO' COMPETITIVE GENERATION SECTOR WITH GENCO'S AND IPP'S COMPETING EQUALL FOR ALL GENERATION.	SAME AS 4.	SEPARATES TRANSCO'S FROM OTHER INDUSTRY SEGMENTS. COMPETITION FOR ALL GENERATION IMPLIES CHANGES IN PURPA REQUIREMENTS FOR QF'S. GROWTH OF REGIONAL TRANSCO'S TO BE ENCOURAGED.

The technical problem areas associated with increased wheeling and transmission access, the potential structural changes in the utility industry, and the increased levels of non-utility generation are related to:

- transmission network physical limitations,
- system planning, operations, engineering, and
- industry structure and institutional relationships.

Table 1.2 summarizes the organizational entities, the assignment of the responsibilities for the three major technical functions under each scenario and indicates the mechanisms for institutional relationships. The technical functions fall under three categories:

1. operating and control (including the responsibility and authority for scheduling generation and transmission flows),
2. planning and development (including responsibilities for planning and development of new transmission and generation facilities), and
3. system engineering (including the responsibility and authority for establishing reasonable engineering standards for transmission system access and for seeking solutions to system-wide engineering problems.)

Primary responsibility assignments are denoted on the table by an "X" with a "C" indicating that responsibilities would be assigned by contracts between the parties.

In Scenarios 4 and 5 the TRANSCOs or T&D Companies would have the option of acting as power brokers (denoted by a "B" on the table.) In the last two scenarios the TRANSCOs would take on an oversight and coordination responsibility in the generation planning area in order to perform the transmission planning and development functions.

		SYSTEM ENGINEERING		
SCENARIO NUMBER	ENTITIE IN THE INDUSTRY STRUCTUR	SMISSION CCESS NDARDS	STABILITY, DYNAMICS, ETC.	IMPLEMENTATION OF SOLUTIONS TO SYSTEM PROBLEMS
1 STRENGTHEN EXISTING	UTILITIE		X	X
	OFS & IP		C	C
	RETAIL			
	CUSTOMER		C	C
2 EXPANDED ACCESS	UTILITIE		X	X
	OFS & IP		C	C
	RETAIL			
	CUSTOMER		C	C
3 NEW SOURCE COMPETITION	UTILITIES		X	X
	GENCOS		C	C
	OFS & IPP		C	C
	RETAIL			
	CUSTOMERS		C	C
4 ALL SOURCE COMPETITION	T&D CO.S			
	TRANSCOS		X	X
	GENCOS		C	C
	OFS & IPP		C	C
	RETAIL			
	CUSTOMERS		C	C
	DISCOS		C	C
5 COMMON CARRIER	TRANSCOS		X	X
	GENCOS		C	C
	OFS & IPPS		C	C
	RETAIL			
	CUSTOMERS		C	C
	DISCOS		C	C

SYMBOLS:

X - PRIMARY RES
O - OVERSIGHT A
B - POWER BROKE
C - ESTABLISHED

1.3.1 Physical Limitations

The basic physical limitations in existing transmission systems are unaffected by the institutional structure of the industry. Barring any dramatic, major improvements in the technology of electric power systems, thermal limits will remain and systems will still need to guard against dynamic problems. Reserve levels of both generation and transmission capacity will need to be provided to ensure system reliability and prevent cascading blackouts and system operators will still need to operate the systems within frequency and voltage tolerance limits.

1.3.2 Industry Structure and Institutional Relationships

The various changes in the industry posed by the scenarios influence, to varying degrees, the accomplishment of the required planning, development, system engineering, and operating functions. With the current industry structure, the responsibilities and authorities for these functions are well established and defined. When there is a technical problem involving both the transmission and generation subsystems, the vertically integrated utility can seek a solution and implement it. When technical problems involve interconnected (and generally non-competitive as well) utilities, they voluntarily cooperate in order to seek conducted, joint solutions with each participant contributing to the solution implementation.

The different industry structures affect the nature of the problems in system planning, operations, and system engineering. With an industry structure with integrated utilities, the technical problems in planning and operations are treated as problems to be solved for the good of the entire utility and its customers.

With non-utility generation competing with utility generation for the market, however, the economic objectives of the various entities may be different. The non-utility generator has the goal of maximizing his profit, the TRANSCO may be controlling the system to meet all its obligations with the goal of maximizing system use within economic and technical constraints and the DISCO is interested in achieving minimum revenue requirements. The GENCOs and IPPs would wish to produce maximum sales unless compensated for "lost sales" (that is, power curtailed for purposes of controlling the system's operations). The TRANSCO with its responsibility to operate the system reliably and securely has a technical need to control the generation and transmission network flows.

The solutions to the various system planning and system operating and scheduling problems will take different forms in different industry structures. For example, as long as the existing utilities are on the scene and control the majority of the generation resources (i.e., that is through Scenario 3), the generation scheduling and economic dispatch procedures may be based on existing methods. When all of the generation resources are under the control of independent GENCOs and IPPs (viz., in Scenarios 4 and 5), the scheduling and economic dispatch methods may be entirely different.

With the disaggregated industry structures envisioned in Scenarios 3 through 5, problems involving more than one segment of the bulk power system will have to be implemented by negotiation, contract terms, new engineering and economic techniques for planning, scheduling and controlling generation, and transmission. Technical problems involving interconnected systems and requiring coordinated engineering studies and solutions may need to be conducted in a competitive environment.

Current experiences with wheeling arrangements shed some light on the effectiveness of this mode of implementation. Informal discussions and surveys of utility organizations indicate that where non-competing organizations have been involved in wheeling negotiations, there have usually not been insurmountable barriers to the establishment of satisfactory wheeling arrangements. When competition has entered the scene, arrangements are frequently contested and lead to hearings and requests for regulatory or legal resolution.

Discussions with utility people throughout the world concerning wheeling arrangements have elicited frequent comments to the effect that when legal considerations come into play before engineering arrangements have been worked out, wheeling arrangements are almost always unsatisfactory. Gentlemen's agreements between utilities that recognize, amongst other things, the physical realities of the systems' limitations appear to have played a large role in making past arrangements for wheeling. The introduction of competition and requirements for legal consideration as a first priority have been reported to make these arrangements more difficult to implement in a satisfactory technical manner. (Or as one utility engineer in Germany stated, "...When contract terms are dictated by lawyers, they are always unenforceable and impossible.")

Be that as it may, the purpose of this report is to explore the technical problems, solutions and requirements for investigation of technical-analytical issues and the development of new methods for such things as transmission scheduling raised by the five scenarios set forth. Each succeeding scenario envisions a greater degree of participation in the generation market by non-traditional utility subsidiaries and non-utility entities. Each scenario poses a different level of access to the transmission system and increased wheeling of power.

1.4 TECHNICAL PROBLEMS POSED BY SCENARIOS

The technical problems raised by these scenarios may be divided into those associated with the increased involvement of non-utility generators and those caused by the increase in transmission system access and wheeling. Each scenario poses differing levels of these activities. The next two chapters discuss technical problems in this framework. Chapter 2 is concerned with the problems associated with integrating non-utility generation sources into the systems and Chapter 3 is concerned with problems and solutions associated with transmission access and increased wheeling.

The technical problems are, of course, closely interrelated: the discussions overlap to some extent. They fall into the broad categories listed below along with sub areas.

1. Problems related to system operations and control;
    a. AGC systems for frequency and tie line control,
    b. generation scheduling and dispatch for system security, spinning reserves and economy,
    c. generation and system VAR source control for maintaining adequate voltages, and
    d. scheduling and controlling transmission flows.
2. Problems related to system planning and development;
    a. generation planning and development for maintaining adequate reserves,
    b. transmission planning and development to accommodate new sources and increased transmission uses, and
    c. identifying transmission limitations and increasing transmission system capabilities.
3. System engineering problems;
    a. defining and measuring transmission capabilities for reliable power transfers,
    b. identifying and solving dynamic problems, and
    c. emergency planning and restoration.

The increased level of non-utility generation in each succeeding scenario affects the relative importance of these problems. At one end of the spectrum in the first scenario, generation ownership, control and responsibilities for system planning and operations continue as they are at present. In the last scenario matters are entirely different. There is a real need to define available transmission capacity in a simple form for ease of conducting negotiations for supplies and system access. Transmission system scheduling to accommodate the numerous contracted transactions will be important. The control of the generation system will be a divided responsibility that will require new techniques and arrangements to handle unit commitment and spinning reserves. Economic dispatch as practiced in current systems may vanish and be replaced by a new technique to schedule transactions only. Economic models and scheduling techniques may be needed to compensate independent generation entities for providing reserve service, participating in voltage control, and for allowing system control over generation levels to aid in system security and transmission system scheduling.

As wheeling and transmission access increase in each succeeding scenario a similar increase in the nature and volume of technical problems occurs. Unambiguous definitions of transmission capability will be required. In the first scenario where the increases posed are modest, technical problems are similar to the current set of problems. In all the scenarios, line capabilities and transfer capacities may need to be increased to accommodate increased demands for wheeling. The uncertainties associated with planning problems would increase as the number of entities involved in wheeling increased. These would be incremental increases in the technical problems associated with planning, operating, and system engineering.

In the last scenario the entire system is operated on the basis of transactions negotiated with the various parties. Transmission system scheduling may replace the economic dispatch of generation as the primary control mechanism for the independent transmission companies. They will need to devise control schemes to accommodate the numerous short and long term arrangements for delivering power from multiple, independent services to the purchasers, over transmission systems with limited capability. Coordination of operation between interconnected transmission networks may play an even greater role in Scenarios 4 and 5 than it does at present.

CHAPTER II

CHAPTER 2

NEW GENERATION SOURCES

2.1 ACCOMMODATION OF NEW SOURCES UNDER EACH SCENARIO

Each scenario raises an increasing number of technical problems as the conditions postulated depart further from the existing industry structure. The increasing freedom of transmission access and levels of wheeling required are accompanied by an increased number of entities participating in the supply of generation. The conditions of each scenario relevant to the expected new sources and associated technical problems related to the new generation sources are summarized below along with an introduction to these problems.

2.1.1 Comments on Scenario 1 - New Sources and Related Technical Problem Areas

The first scenario does not envision any drastic change in the industry structure. Non-utility generation would continue to be developed under PURPA and IPPs would be allowed to enter the market.

New, non-utility generation sources expected, include the existing pattern of QFs and may also include larger units constructed by IPPs specifically to enter the market. The dispatchability, operation, and control of non-utility generation and their effects on system costs will become more significant to more utilities if the level of this type of capacity on the systems increases and is more widespread. This also increases the uncertainty in generation planning since the independent, non-utility generation that is planned frequently has not materialized and there is concern on the part of utilities about the longevity of these new sources.

The technical problems existing in today's systems would not be seriously changed by this scenario, although their frequency would be expected to increase as the number of non-utility sources increased. The mechanisms for implementing solutions would remain since system planning, operating and engineering functions would be basically utility responsibilities, except for the operation of non-utility generation.

2.1.2 – Scenario 2

The second scenario also leaves the vertically integrated utilities in place and does not alter the situation regarding the entry of new generation sources. The mix of new, non-utility generation would be the same as in Scenario 1.

Access to the transmission system is expanded by allowing mandatory wheeling for both utilities and large retail customers (i.e., retail wheeling in the sense used here). These retail wheeling transactions affect the system control since the wheeling utility would need to establish satisfactory terms and conditions for dispatching, control, and standby reserves for contracts between the generator and retail customer. In this scenario the additional technical problems arising from the new generation sources are related to these new factors and control requirements.

The treatment of retail wheeling in the generation scheduling and AGC systems will need to be developed to fit the specific circumstances. The introduction of retail wheeling in this scenario may upset the voluntary cooperation between interconnected utilities that has aided in the control of interconnection flows (i.e., tie line flows), loop flows, inadvertent interchange levels and has encouraged reliable system operating practices.

Technical issues raised would have to be attacked and solved on a case-by-case basis as they are currently. Rules would need to be established regarding system operation, reliability, etc., that are highly system dependent.

2.1.3 Scenario 3

Scenario 3, Competition for New Bulk Power Supplies, leaves the vertically integrated utilities in place and allows them to enter the competitive market for any new generation capacity required by establishing GENCOs. These organizations, along with IPPs, would bid for the contracts for new generation sources.

New generation requirements, planned by the utility's staff, would determine the types and sizes of the new sources. These would be expected to span the complete range of existing, utility owned, fossil fueled, and hydro generation as well as the new sources expected in the previous scenarios. In addition there will probably be GENCOs established to own and operate existing, or as yet unfinished, light water moderated nuclear plants constructed by utilities.

Technical Problems

The major technical problem areas would be in 1) the scheduling of generation and transmission, 2) economic dispatch, and 3) AGC areas. They result from the growth of non-utility generation and the increased wheeling transactions. The new generation would supplant the existing (i.e., "old") generation after some time and the scheduling and AGC problems would involve a much higher portion of non-utility generation plus utility generation that may be located in interconnected utility systems. In the long term this scenario evolves to the conditions of Scenario 4, with all of the generation owned by independent entities.

Technical-Economic Problems

Technical-economic questions that arise in system planning, operation and control as a result of these new sources include the following.

- How do the systems obtain new resources required for reserve purposes rather than energy production?
- When wheeled power and non-utility generation form a larger portion of the system generation, what form does the economic model take for the system unit commitment and economic dispatch?
- What type of costs and economic models are involved in compensating generating entities for providing controllable VAR support, regulating duty and spinning reserve service and controllable generation for stability, security and transmission system dispatch purposes?

Institutional Problems

Both Scenarios 2 and 3 contain technical problems that are related to the institutional arrangements as well as to the new sources. System dispatch could still be done on the current economic basis with some modification for the new source generation contracts and their terms. Marginal operating costs for generation would retain essentially the same meaning that they have currently. The dispatching of individual systems and power pools, mechanisms for arranging economy interchange transactions and the operation of power brokers could all continue as at present.

2.1.4 Scenario 4

The penultimate scenario extends the competitive market to include all generation supplies required, both old and new. Integrated utilities are gone from the scene. Independent GENCOs compete with IPPs for all supply contracts. Transmission and distribution functions are retained in utilities, T&D Cos. for a combination company and TRANSCOs or DISCOs if separated. The TRANSCO (or "T" in the T&D Co.) has responsibility for system reliability, and it is assumed that the TRANSCOs are assigned the responsibilities for system operations, generation and transmission systems' scheduling and system engineering.

System scheduling and dispatch are to be performed under contract terms between generators and T&D Cos. or retail customers. Retail wheeling is voluntary and so is not expected to affect operations as much as in Scenario 2.

New generation sources would have the same type and mix pattern as in the previous scenarios. Existing utility generation would initially constitute the vast majority of the generation capacity. Customer determined needs would dictate the expansion of the system.

New and specific technical problems arise immediately in the generation scheduling and control areas. The TRANSCO must establish means for ensuring a reliable generation supply and for scheduling generation to meet load demands on a secure basis, requiring a new approach. Existing unit commitment scheduling methods will require modification.

Existing methods minimize total system operating costs for the entire array of units. Schedules are developed for the economic benefit of the whole system, not for that of any particular unit or plant. With divided ownership of the generation the economic scheduling of generation becomes an entirely new problem where each party has an interest in maximizing his own benefit.

The same technical problems arise in Scenarios 3 and 4 except that they would occur more rapidly in 4. The shift in responsibility for establishing adequate generation capacity reserves arises in 4.

The established pattern of generation scheduling and economic dispatch by present integrated utilities would be replaced by one that involved the assignment of the responsibility for system control to the TRANSCO in both 4 and 5.

Technical problems in this scenario are also expanded by the requirement to make additional specific arrangements for adequate voltage control. The TRANSCO would have to develop means for arranging and implementing the economic control of VAR generation, spinning reserve service and generation level adjustments for security and transmission system scheduling.

With the generation schedules based on the supply contracts, the current meaning of system incremental production costs may be lost. When contracts between sources and customers are the major part of the resources being scheduled, the goal of dispatching generation sources to achieve a uniformity of marginal production costs throughout the system may disappear. Schemes with the goal of scheduling generation to satisfy the contract requirements, observing the limited transmission and security constraints, will become the new framework for generation dispatching and control.

Economic dispatch using incremental costs might only be done by GENCOs and IPPs for groups of units under their individual control.

The possible loss of the current commonly accepted meaning of system-wide incremental costs also has the potential for upsetting current contracts for energy purchased by utilities under avoided cost contract terms.

TRANSCOs require the ability to monitor and control all of the generation resources. System operating control center software would be redesigned so that power could be transmitted for other parties or brokered by the TRANSCO. Transactions costs, metering requirements, billing system complexities, and computer resource needs will all increase.

TRANSCOs will control AGC systems to ensure the maintenance of constant frequency and control interchange schedules. This function will need to be expanded with the increase in new sources. The effective number of control areas may have to be changed depending upon the nature of the various contracts and the extent of TRANSCO service areas.

The removal of the integrated utility from Scenarios 4 and 5 introduces difficulties in attacking system engineering problems such as stability, subsynchronous resonance, low frequency power oscillations, and both emergency and post-emergency restoration planning and operations. Means will be required to ensure cooperative efforts to expedite and implement solutions to prevent the degradation of system performance that could be caused by the lack of a timely cooperative effort.

For example, low frequency system power oscillations may be due to the interaction of the system controls, the electro-mechanical parameters of the generation systems, and the particular electrical properties of the transmission system. They may be initiated by electrical transients caused by major load switching actions. In an environment such as posed in Scenarios 4 and 5 responsibility for seeking and implementing solutions is divided among numerous, independent generating sources, transmission companies, and the customer organizations. This division of responsibility could lead to chaotic system conditions causing frequent system separations and interruptions. Institutional arrangements under Scenarios 4 and 5 must be made to prevent this. Arrangements must be such to ensure that some organization, probably the TRANSCO, has the responsibility for system-wide engineering and that all other organizations are required to participate in the required solutions and implementations.

2.1.5 Scenario 5

The last scenario opens transmission access on a non-discriminatory basis for both retail and wholesale wheeling to all parties. The terms of the scenario require the complete separation of the utilities into GENCOs, TRANSCOs and DISCOs. The TRANSCOs are to be regarded as common carriers with the responsibility to provide for adequate transmission capability. In order to make this scenario practical the TRANSCO would need to be assigned additional responsibilities and authorities in system operation and planning and assume a role similar to the one played in Scenario 4.

The new generation resources and technical problems are the same as those in the previous two scenarios. The non-discriminatory requirement to provide wheeling service is extended to apply to both generators and retail customers, reintroducing the operating and control problems associated with retail wheeling discussed in Scenario 2.

All generation planning would be vested in contractual agreements between generators and DISCOs unless the TRANSCOs act as brokers. The TRANSCOs are responsible for supervision of system operations and assume current and expanded control center functions. The nature of the technical problems would be the same as those in Scenario 4, but expanded to include those generation scheduling and control problems due to retail wheeling.

2.2 SIGNIFICANT SUPPLY CHARACTERISTICS

Generation supply characteristics are important parameters in assessing system control and dispatch. Economic operating characteristics, control ranges, and generation response data are all important factors. Loads change rapidly and generation must be capable of responding. Rapid response is needed to restore tieline flows after forced outage events. During light load periods, the system may be required to shut down generators to keep generation and load in balance. Under the current arrangements utilities can control these characteristics by installing various types of units.

The coordination of new generation characteristics with utility generation is one technical problem that requires attention, particularly in Scenarios 3, 4 and 5. In the first two scenarios, the conditions posed do not provide a mechanism for specifying new source characteristics. The existing array of generation will have to accommodate whatever characteristics the new sources have. This is the situation in utilities presently where QFs and cogenerators have appeared.

In the last three scenarios, the mechanisms do exist to coordinate the new source characteristics with existing capacity. In Scenario 3 the new source characteristics may be specified as part of the bidding process. The same is true in Scenario 4 as long as the TRANSCO has the responsibility and authority for system operations and planning. All source supply coordination would then be similar to that expected in Scenario 3.

This is a key question in Scenario 5. The ac electric power system with presently available apparatus will not function correctly with proper voltage levels and frequency unless the coordination takes place. For example, it would be chaotic to have all base load generation supplying today's form of highly variable load cycles. Coordination will have to be the responsibility of the TRANSCO. Sufficient plant capacity must be available for frequency control and load following.

The level of coordination required is that practiced in current utilities. The generation system characteristics must be able to match the load patterns. Load following must be done by some capacity. Sufficient capability must be under AGC and capacity has to be available to handle peak loads and outages of generation. Coordination of fuel supply requirements and other characteristics would be left to the market to be arranged by contracts.

The only other technical alternative that appears conceivable is to require sufficient load management and direct load control to level the generation demand cycle. Even then some coordination of unit characteristics and control is required to handle generation demand level changes due to outages and fluctuations caused by non-controllable generation output levels such as in solar, wind, etc., installations.

Coordination of planned generation outages is not a serious technical problem when sufficient installed capacity reserves are available. In the different scenarios a number of different approaches to this coordination may be proposed. With mostly utility controlled generation the IPPs would be free of constraints. More non-utility generation planned maintenance schedules might be established by contract or a bidding process. Unplanned maintenance outages must be considered in coordinating maintenance outages as a random variable.

The range of unit sizes and types of new sources in the various scenarios extends from smaller QF units up to the existing 1000 MW nuclear units constructed by utilities. New fossil fired steam units would probably be limited to maximum sizes of 500 to 600 MW assuming continued low load growth rates. Fuels expected for these new sources may be coal, gas, or even oil depending upon the fuel availability, price levels and regulations concerning fuel use and environmental control requirements.

Small hydro units and municipal refuse burning plants are possible contributors to the new source picture. Cogenerators with new plants would be expected to be combined cycle plants burning natural gas because of their simplicity, shorter lead time requirements, and relative economic advantages. Cogeneration installations for larger refineries and chemical plants may reach 1000 MW or more.

IPPs may be induced to install gas turbine peaking capacity burning natural gas. Sizes for advanced design units range up to about 130 MW currently.

New source generation characteristics of importance in reviewing the technical problems associated with the five scenarios are:

- heat rates and control ranges,
- unit availability and expected maintenance outage time,
- response rates,
- fuel and environmental considerations,
- lead time requirements,
- long term plant availability of new sources, ,
- coordination of plant characteristics with utility, and
- plant location and transmission access.

2.2.1 Heat Rates and Control Ranges

Heat rates for steam units are important determinants in economic scheduling (i.e., dispatch) of systems. Under some scenarios it is probable that non-utility generation would be controlled economically along with existing generation.

Typical net heat rates and control ranges for fossil fueled steam plants of various unit sizes and fuels are given in Table 2.1. Heat rates and control ranges will vary depending on plant design, auxiliary systems and plant controls,as well as the unit's age and condition. Heat rate data are all for the higher heating values of the fuels.

A 1979 EPRI report, "Survey of Cyclical Load Capabilities of Fossil Fired Generating Units", Report EL-975, Technical Planning Study (TPS) 77-732, provides additional data on unit minimum load capabilities and regulating ranges. These data are in general agreement with those on Table 2.1. The survey shows that the exact characteristics depend to a great extent on plant designs, boiler type,and boiler control systems.

Light water moderated reactors have typical full load net heat rates of 10,400 Btu/kWh. Control ranges of nuclear units extend down to approximately 20 to 25 % of maximum capability. It has not been the practice in U.S. systems to operate these plants as load following units. This is apparently due to the lack of need to do so, since the percentage of nuclear capacity is not large, plus the reluctance of nuclear plant owners and operators to subject the units to unnecessary power excursions.

TABLE 2.1

Typical Fossil Generation Unit Heat Rates

Fossil unit-description	Unit Rating (MW)	100% Output (Btu/kWh)	80% Output (Btu/kWh)	60% Output (Btu/kWh)	40% Output (Btu/kWh)	25% Output (Btu/kWh)
Steam--coal	50	11000	11088	11429	12166	13409*
Steam--oil	50	11500	11592	11949	12719	14019*
Steam--gas	50	11700	11794	12156	12940	14262*
Steam--coal	200	9500	9576	9871	10507	11581*
Steam--oil	200	9900	9979	10286	10949	12068*
Steam--gas	200	10050	10130	10442	11115	12251*
Steam--coal	400	9000	9045	9252	9783	10674*
Steam--oil	400	9400	9447	9663	10218	11148*
Steam--gas	400	9400	9548	9766	10327	11267*
Steam--coal	600	8900	8989	9265	9843	10814*
Steam--oil	600	9300	9393	9681	10286	11300*
Steam--gas	600	9400	9494	9785	10396	11421*
Steam--coal	800-1200	8750	8803	9048	9625*	
Steam--oil	800-1200	9100	9155	9409	10010*	
Steam--gas	800-1200	9200	9255	9513	10120*	

Note: Points noted with an asterisk are outside of normal control range.

Source: Chapter 2 of "Power Generation, Operation and Control" A. J. Wood and B. F. Wollenberg, John Wiley and Sons, Inc. 1984

Plants using combustion (i.e., gas) turbines have typical heat rates as shown on Table 2.2.

TABLE 2.2

Typical Gas Turbine Plant Heat Rates

Plant Type	Heat Rate (Btu/kWh)
Industrial Existing	13,600
Advanced Design	9,500 to 11,300
Jet	16,000
Combined Cycle	8,500

These data are also for the higher heating value of the fuels. They are also approximate, particularly for combined cycle plants where the efficiencies are very dependent on the cycle design.

Control ranges are from 20 to 100% of rated capacity. Combined cycle plants in modern cogeneration plants are operated to meet steam demands. The control range at a given steam requirement operating point is very limited: exact ranges depend on the specific design.

2.2.2 Maintenance and Unavailability Characteristics

The overall availability of generating units affects generation system reserve requirements and operating economics. Table 2.3 shows typical maintenance and forced outage experience for various types and sizes of units.

TABLE 2.3

Typical Maintenance and Forced Outage Data

Unit Type	Size Range (MW)	Maintenance Requirements (Day/Year)			Equivalent Forces Outage Rate (%)	Availability Factor (%)
		Scheduled	Unplanned	Total		
Nuclear	All	63	9	72	16.7	68
CTs	All	11	6	17	--	90
Fossil Fueled Steam	1-99	25	7	32	10.5	83
	100-199	36	9	45	9.5	81
	200-299	41	8	49	9.4	79
	300-399	41	8	49	13.8	79
	400-599	39	7	46	9.6	76
	600-799	43	5	48	12.0	78
	≥800	43	7	50	10.4	81

Table 2.3 Notes:

1. Equivalent Forced Outage Rate is (Forced Outage Hours + Equivalent Forced Derated Hours) divided by (Forced Outage Hours + Service Hours), both taken for the same time period.

2. Availability Factor is the ratio of the hours the unit is available for service divided by the hours in the period.

Source: NERC Equipment Availability Report 1985

2.2.3 Unit Response Rates

The power systems' changing load patterns, the need to participate in frequency regulation, and the need to be able to respond to emergency and other special situations that arise on the system, all lead to requirements on generating units for changing load. The key measure of a unit's ability to respond to these requirements is its response rate expressed in MW/min or in percent of rated capacity per minute (%/min). Generating units generally have the capability of responding more quickly over limited excursion ranges for shorter time periods.

Figure 2.1 illustrates the power system response requirements, shows the various time periods involved in various system requirements,and provides a way in which to characterize a particular unit's performance characteristics. Note that the scale is log-log. The horizontal scale is the required time interval. The vertical scale is the response rate in % MW per minute and the diagonal lines connect points that have identical excursions. The points labeled "A" and "B" on the figure connect performance parameters for small and large excursions for a single hypothetical unit.

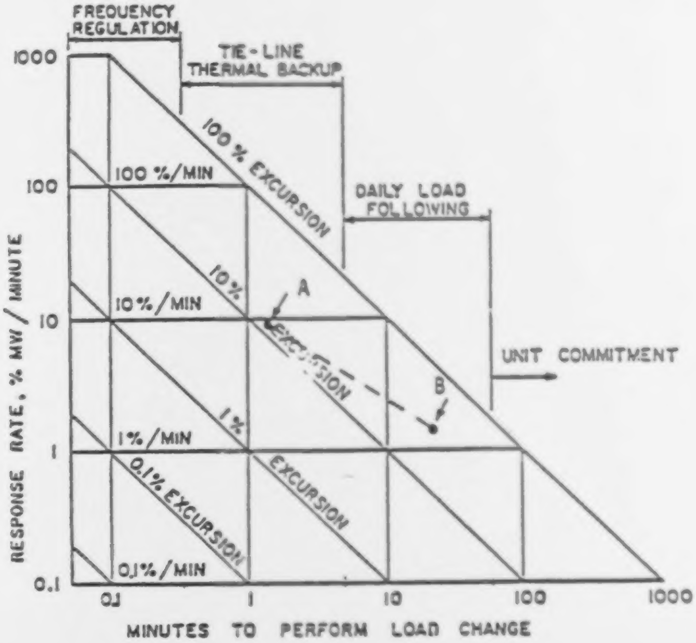


Figure 2.1 - Power System Response Requirements Representation

Source: "MW Response of Fossil Fueled Steam Units", IEEE Paper TP 72 633-6, IEEE Working Group on Power Plant Response to Load Changes, Presented Sept. 1972.

Unit commitment duty is taken as any change required beyond 60 minutes in the future. Normal daily load following duty requires response between 5 and 60 minutes. The basic need is to meet normal daily load cycle requirements and economic dispatch control signals. Response rate requirements range up to about 5%/min for individual units even though daily peak load cycles seldom exceed rates of change of 2% of daily peak load per minute.

The AGC system dictated response lies between about 15 seconds and 5 minutes. This is the time period in which it is important to readjust tie line power flows to keep them below the normal line limits. The region for normal frequency regulation is between about 3 and 20 seconds. Special needs are caused by power system stability considerations where units may be called upon to adjust load rapidly to assist in stabilizing a system.

These requirements are given to present a background for summarizing unit response characteristic data. These data, obtained from published industry surveys, are useful in understanding the relative capabilities of various types of generating units in responding to the needs for response.

A 1965 survey, "Power Plant Response," an IEEE Working Group paper on power plant response to load changes, presented the results of a survey of the rate of load change experienced and the response rates of various types of units. Results are summarized on Table 2.4. The data shown are representative of the median results of the survey and are typical of current power plant response characteristics.

The 1979 EPRI survey report cited previously (EPRI Report EL-975) contains additional data concerning response rate characteristics. The results, in general agreement with the earlier survey, show the variations in response rates due to boiler designs and fuel type.

TABLE 2.4

Typical Response Rates

Unit Type and Size Range	Response Rate
Steam Units (all fuels)	
10-50 MW	4.8 %/min
60-199	3.8 %/min
200 and over	2.8 %/min
All Sized	
Non-reheat	4.2 %/min
Reheat	3.0 %/min
Hydro Units[1]	
10-59 MW	1 to 6 %/second
above 60 MW	4 to 6 %/second
Gas Turbines[2]	
All	About 50% of the units were designed for instantaneous response. The median capability said to be "maximum instantaneous response" was 55% of rating.
Units without full instantaneous response	Median response rate 0.9 %/sec

Table 2.4 Notes:

1. The hydro unit response rates depend upon the plant's net head, the type of hydraulic turbine and the length of the penstock.

2. Gas turbine response rates vary depending upon the design of the particular unit. These data indicate that a response rate of about 55% per minute is the median value.

Source:

"Power Plant Response," IEEE Working Group on Power Plant Response to Load Changes, IEEE Paper TP 65-771, 1965.

Nuclear power plant response rates have been surveyed by CIGRE Study Committee 39 and published in PC 85 01A for a Study Committee 39 meeting in Toronto, Canada, held September 16-21, 1985. The survey covered units throughout the world, including all types of commercial power reactors. The results indicate that over 50% of the reactors represented in the survey utilized normal loading rates between 4 and 5%/minute. One conclusion that may be drawn is that utilities with large concentrations of nuclear power plants are generally able to use these plants for load following and regulating duty.

The data were not reported by country so that it is not feasible to extract specific numerical data concerning the response rates of light water moderated reactors in the U.S. However, in a subsequent report of this same CIGRE Committee ("Cycling of Nuclear Power Plants To Meet Grid Operational Requirements," for a meeting of this group in Tokyo, Japan on October 27-28, 1987), the situation in the U.S. regarding nuclear reactor power plant operations was summarized as follows:

> "Operating strategies in the USA have, until recently required NPPs (nuclear power plants) to operate in a base-load regime only, although many utilities have engaged in tests on nuclear plant in a load following and generation cycling regime ... currently generation cycling (100 - 65-100%) is reported to be a regular occurrence with its BWRs and early PWRs. AGC is also implemented on NPPs by CE (Commonwealth Edison) but only infrequently ... at the present time the Task Force is unaware of particular units intended for hosting AGC."

2.2.4 Fuel and Environmental Considerations

The new sources would be expected to have the same concerns over future fuel availability and price levels as existing utilities. Regulations applying to new source fuel use should be the same as those for the utilities. Natural gas fired generators constructed for cogeneration enjoyed a fuel source advantage denied to utilities.

Long term availability, price levels, and price stability of fuel resources are unknowns for both utilities and non-utility generators. It appears that coal resources are plentiful for the longer term. Natural gas is currently in abundant supply, but it is not clear if this situation will persist in the long run if a large portion of new generation sources are fueled by gas.

Oil availability and all fossil fuel prices have been tied together by the market and supply management actions of OPEC. Currently oil appears to be in abundant supply with fairly stable price levels. Since the U.S. is dependent upon imported oil for a large part of its requirements, unforeseen world events have the capacity to rapidly upset the market.

Fuel price levels have been volatile since the early 1970's. Long term fuel price forecasts have been somewhat inaccurate as a consequence. Therefore, it is probable that new source generation will be secured under terms that allow for fuel price adjustments in the price of IPP delivered energy.

Environmental considerations and regulations have affected new generation costs and fuel selection. In these scenarios it is to be expected that any such considerations, requirements for control and restrictions would apply uniformly to utilities, GENCOs, and IPPs. The past impact on utility system planning has been the general movement to using coal fuels for future plants. Environmental considerations and added costs for controls have somewhat dampened enthusiasms for coal.

The planner has to make the choice among fuels. Coal is in abundant domestic supply. Prices are relatively stable. Environmental costs add to plant costs. On the other hand, natural gas availability and prices are more uncertain, but gas fired plants are more environmentally acceptable without major added control costs. Oil availability and price levels are more uncertain. Environmental costs are higher than for gas and may even approach those for coal. These considerations will apply in the future for all new source suppliers. With generation being supplied by IPPs in some scenarios, fuel planning is decentralized and may lead to more gas fired capacity since this fuel appears to offer the fewest problems.

2.2.5 Lead Time Requirements

Another factor affecting planning and system development is the lead time required for new sources. Utilities have experienced increasingly long time requirements. They face regulatory hurdles as well as the expected requirements for permitting and construction cycles. In scenarios where new sources are removed from regulation, plant lead times would be expected to decrease. The lead times would approach those for current non-utility plant construction. Environmental regulation would still exist and would be applied equally to all new generating sources.

Cogeneration plants have been planned, engineered and constructed in 2 to 3 year cycles or less for smaller sized plants. Utility construction has generally been longer, ranging from 5 to 6 years or more.

With the low growth rates of load in recent years, longer lead times have not resulted in shortages of generating capacity. When requirements for new sources arise, planning should be performed sufficiently in advance to allow selection out of an array of possible fuel supplies and new source entities (depending, of course, on the scenario). Without sufficient lead times the choice may be restricted to oil or gas fired plants using combustion turbines. These plants generally have much shorter construction cycles since the units are factory assembled and do not require extensive fuel handling equipment, boilers, and plant control systems.

New source lead times interact with lead time requirements for needed transmission construction. Non-utility generators need to coordinate plans with the utility or TRANSCO to make certain that transmission will be available on time. Transmission lead time requirements are highly system and site specific.

2.2.6 Long Term Availability of New Sources

The concern with long term availability of new sources is primarily with those to be supplied by QFs and cogenerators. GENCOs and larger IPPs supplying generation could be bound by long term contracts.

QFs and cogenerators may or may not be as long lived as past utility generation. QFs may find the business unprofitable if avoided utility costs and their revenues decline. Cogenerators may experience economic downturns and curtail the plant operations with short notice to the utility or TRANSCO.

These are probably manageable uncertainties in reasonable quantities, but many will argue over the definition of "reasonable quantities." An increase in uncertainty level means that generation capacity reserve levels will have to be adjusted upwards by utilities or TRANSCOs and DISCOs to cope with the uncertainty. In Scenarios 4 and 5, the responsibility for obtaining sufficient reserves to ensure reliability is assigned to the purchasers. The mechanisms for obtaining the required reserves are not clear.

Utilities with nuclear capacity actually face the same sort of uncertainties. Unforeseen events cause new regulations to be applied to operating plants causing long time outages. The delays in developing long term means for handling nuclear plant waste products could conceivably result in future plant shutdowns and even retirements ahead of schedules.

2.2.7 Plant Location and Transmission Access

Plant locations and the point of access to the transmission system are system and site specific. Transmission access should be at subtransmission or higher voltage levels to avoid causing excessive technical problems in the distribution system, such as backfeed, excessive short circuit duty requirements, etc. Connection at major substations, or the construction of new stations at or near new source locations, will facilitate the installation of required breakers, protective systems and metering and communication equipment.

If possible, new source sites should be located near existing major substations which may be expanded, with transmission facilities that have sufficient capacity for delivering the power. If not, plant locations and transmission expansion plans require coordination between new source entities and the utility or TRANSCO.

2.3 CONTRACTUAL ARRANGEMENTS WITH NEW GENERATION SOURCES AND EFFECTS ON SYSTEM OPERATION AND ENGINEERING

The technical areas of concern in contracts between new source entities and utilities or TRANSCOs are:

- scheduling and dispatchability of generation,
- AGC system control of generators,
- the economic structures for service in providing,
  1. capacity reserves,
  2. VAR scheduling for voltage control,
  3. system security scheduling,
  4. transmission system scheduling,
  5. energy,
- coordination of bulkpower system planning, and
- coordination of implementations to solutions to system engineering and technical operating problems.

2.3.1 Scheduling and Dispatchability

Contracts need to allow system operators to control the dispatch of a sufficient portion of total generation to follow load cycles and control transmission flows. Lack of control of sufficient generation could lead to generation-load imbalances, more frequent system separation, and greatly increased levels of inadvertent interchange. Unit commitment and generation maintenance scheduling will both need to be covered under the contracts to allow the system control center to schedule sufficient generation to cover spinning reserve requirements. Minimum load conditions may require units to be scheduled off line.

A solution is to require all new source contracts to allow scheduling of generation in a unit commitment conducted by the utility or TRANSCO and to allow restriction of a portion of the capacity towards spinning reserves when necessary. New sources with non-schedulable plants (e.g., some cogenerators) would be excused, but might be required to purchase an equivalent amount of operating reserve capacity as a condition of access.

In the scenarios with the majority of generation controlled by utilities, current practices can initially be extended. Non-utility generators have freedom to schedule their own resources. At some point in the growth of non-utility capacity the dispatching and scheduling difficulties must be addressed in contract terms. When the new sources increase to the point where the minimum load level commitment and dispatch are constrained, contract arrangements should allow the scheduling of new source generation. The terms and rate structure for allowing this will need to be addressed in the contracts.

In Scenarios 1, 2 and 3, generation scheduling and dispatch might be done under economic terms of contracts. Under Scenarios 4 and 5 (and ultimately under Scenario 3 when the new sources displace utility generation) the situation is different since all generation is "new source." Contract terms will need to allow the TRANSCO system operators the ability to schedule sufficient units to follow load cycles and meet security, spinning reserve requirements, and transmission constraints.

Contract terms will need to be set for scheduled maintenance outage coordination in order to ensure that there are adequate generation reserves available throughout the year.

Solution methods could involve the TRANSCO acting as a broker of reserves. Each new source would be obligated by contract to supply capacity and reserves. When units were unavailable due to planned outages, maintenance outage caused by failures, or by forced outages, the generation supplier would be obligated to purchase reserves with the TRANSCO acting as a broker.

Another solution would be to have all supply contracts directly between sources and DISCOs, and retail customers carry an obligation that the source furnish or purchase reserves. Maintenance scheduling would then be left to individual new source entities.

In all solutions the TRANSCO would act as a coordinator, keeping track of available capacity, reserve obligations, and assisting in making arrangements.

Present economically determined participation in load following may be replaced by specific contract terms defining the operating control range and the level of participation for each generation source. Some units may be base loaded, essential off control, while others may be scheduled off line at low loads and have their output levels controlled when online.

Retail wheeling contract terms may be designed so that the supplier is required to dispatch his generation on the basis of the purchaser's load cycle including spinning reserve requirements. The supplier could maintain his own control center, but the TRANSCO would require monitoring capabilities and the authority to order generation changes for system security and in system emergencies.

The arrangements may be similar to those in the current NEPOOL system with different levels of control (i.e., a hierarchical control system structure), with the TRANSCO taking the role currently played by the regional control center (i.e., the New England Power Exchange, or NEPEX Center) and the generating entities acting similarly to the current area control centers. Different independent power producers would be scheduled by the TRANSCO to provide total generation levels. The allocation and scheduling of individual units might then be left to the IPPs. The major difference between this and the arrangement in NEPOOL is that the loads and generation areas may not be contiguous as at present. Net deficits of inadvertent interchange would be purchased by the source from the local utility. Rates would be set by contract terms.

Other contract arrangements between individual new sources and retail customers are possible. A supplier, for example, might be required to purchase reserves in lieu of allowing control for dispatch and scheduling. The TRANSCO might act as a broker in this case, arranging terms between sources for this service.

2.3.2 AGC System Control of Generation

Contract terms must address the subject of AGC system control of generation. In the first scenarios, control of individual new sources may be handled utilizing the current system of control areas, etc. Retail wheeling introduces new AGC related problems and contracts must address load following for specific customers, standby service and inadvertent interchange. In the last scenarios, a global solution needs to be addressed with the definition of control areas and ties between areas requiring precise definition.

Contracts between sources and purchasers would contain terms allowing for this generation control. The lack of tie line control, allowing all units to be merely on governor control of frequency with supplementary controls to restore set output levels would mean that all generators would attempt to restore frequency in any imbalance between generation and demand. The increased frequency of unit output level adjustments would become intolerable to plant operators because of the potential damage to equipment, increased levels of unavailability, and the reduced lifetime of the equipment. Tie flows and inadvertent interchange levels would rise without adequate capacity under AGC control.

The terms for handling inadvertent interchange and AGC system generation control are closely related. The implementation of coordinated AGC system controls, similar to those currently existing, may allow the continuation of the repayment of inadvertent energy in kind (i.e., MWh for MWh). This is more likely to happen in the first two scenarios assuming a modest level of retail wheeling. In the last three scenarios the number of generating entities may become so large that contract terms will have to address the subject of inadvertent interchange payments.

2.3.3 Economic Structure for Operating Controls

Currently utility generators provide VARS for voltage control, provide spinning reserve capacity, are rescheduled off-economy for security and transmission loading adjustments, as well as supplying power and energy. Under the first two scenarios they could continue to do so, with new sources supplying primarily power and energy. Contracts for new sources may carry requirements for allowing scheduling and dispatching. Economic terms for these services will be set by contract provisions where needed. Voltage control issues should be addressed in all the contracts by allowing the system control center the option of specifying generator VAR levels.

In the later scenarios, the contracts need to address all of these areas. Economic measures of the worth of these services have to be established to allow the system operators to control the system properly. This is a technical-analytical issue that does not have a current solution. It is not an easy area to address. In establishing contracts, questions of the value of these services need to be addressed at the same time as the technical problems associated with the lack of control are considered.

The generating source entities and purchasing entities are bound together by the transmission system. The integrity of this system and its proper operation depend on the actions of all parties. Therefore, there is a high degree of mutual self-interest involved in preserving the system. For example, if generation source operations must be curtailed because of improper voltage conditions caused by lack of system-wide coordination of generator VAR schedules, all parties may suffer. Controlling generator VARs control really does not affect the operating costs of the generating entity in any material way. Payment terms may not be required in contracts.

Contract terms with new sources should establish the basis for setting the economic worth of providing capacity reserves and allowing generation output levels to be controlled to aid in system security and transmission dispatch. In these areas the generating entities still have a self interest in preserving transmission system integrity, but they also may suffer economic penalties if levels of their energy production must be reduced. Contract terms should address the establishment of an economic structure that allows for necessary output level control.

2.3.4 Contract Provisions for Coordination of Bulk Power System Planning

Bulk power system planning involves both the generation and transmission systems. In the first three scenarios the vertically integrated utility remains and can continue to coordinate plans for both of these subsystems.

In Scenarios 4 and 5, there is no single coordinating agency. Contractual terms will need to establish means whereby the TRANSCO can participate in generation planning as well as that for the transmission system. The ultimate responsibility for generation planning under these scenarios rests with the user organizations, but a lack of coordination between users, generators, and the TRANSCOs could easily result in the development of inadequate transmission systems.

At the least the TRANSCOs should be involved to the extent of being given an oversight responsibility in all bulk power planning matters.

2.3.5 Contract Provisions For Resolution of System Engineering And Operating Technical Problems

System engineering and technical operating problems involve both generation and transmission systems, and perhaps even the distribution system. They include such problems as system stability and dynamic problems, the resolution of the need for new VAR sources and controls, emergency operations, etc.

In the first two scenarios the utility remains and has the responsibility for seeking solutions. Implementation may require contractual negotiations with new sources and customers under retail wheeling contracts to cover VAR controls, excitation system modifications, participation in emergency operations, and power factor correction in load areas.

In the last three scenarios the contract terms must be broader and must address the responsibility for seeking solutions to these problems. They must establish the basis to assign responsibilities and costs for needed implementations.

An example is the solution of system stability problems. The TRANSCO's engineering staff would be responsible for detecting the problem and seeking solutions. The potential solutions may involve installing stabilizers on generators, adding controllable VAR supplies on the transmission system or in the load areas, modification of the generator controls, fast run-back of generation levels, addition of series capacitors, etc. The selection of the proper method of solution and the responsibilities and costs for implementing the solution require attention in contracts.

It will prove impossible to foresee all of the specific problems that need attention. Certain areas such as emergency planning and operating procedures clearly need to be addressed in contracts while other areas are less specific. The contracts should establish the mechanisms for resolution of unanticipated system technical problems.

2.4 TECHNICAL PROBLEMS AND POSSIBLE SOLUTIONS

The technical problem areas raised by the new sources involve:

- generation scheduling,
- generation dispatch and load following,
- AGC system and frequency control,
- generation planning and capacity reserves, and
- solution of system engineering problems.

Each of these has related sub-problems that are discussed below along with suggested methods for solution.

They are closely interrelated to the technical problems caused by increased transmission access and wheeling discussed in Chapter 3. Some overlap occurs. This chapter views those related to the new generation sources.

2.4.1 Technical Problems in New Source Generation Scheduling

These include maintenance scheduling coordination and scheduling of units for spinning reserve (i.e., unit commitment.) The relative importance of these are related to the particular scenario as discussed above.

A significant and difficult technical problem is that of scheduling new source generation to accommodate load cycle variations and the need for adequate spinning reserve margins.

Spinning reserve duty could be assigned to all sources of generation on an equal basis. Suppliers with a fleet of units could satisfy the requirement in whatever way they wished. Single units would have to be operated below maximum loading limits which allow for spinning reserves. The TRANSCO requires monitoring and communication equipment to insure that reserve requirement obligations are being met.

Another solution would be to develop an economic model which allowed the system operators to cost and purchase spinning reserves from sources. Generating sources not participating would be allocated these costs by the system control center.

Scheduling units on and off line in unit commitment scheduling is a more difficult technical problem that is related to contractual arrangements. With a few new source generators the right to schedule a unit by a utility might be purchased under contract terms that provided, for example, payments based on what the new source supplier would have received if his unit had been allowed to operate. Utility scheduling software would reconstruct generation patterns and compute payments to the new source. This would be an economic penalty in utility unit commitment determinations and would allow system operators to make an economic choice between shutting down a new source supplier and allowing him to continue operating. New source shutdowns would then only occur when required to meet utility unit operating restrictions.

Shutting down a new source engaged in retail wheeling to a specific customer would entail even more of a penalty to the utility if it is required to supply the replacement energy.

With no integrated utility on the scene in some scenarios, generation scheduling (i.e., unit commitment) has an entirely different objective from at present. One objective of present scheduling methods is to minimize total production costs for the benefit of all of the utility customers. With no utility and a multitude of suppliers and customers, generation scheduling takes on some of the attributes of an OPEC meeting to establish market quotas in an attempt to manage prices. Each OPEC participant is seeking to maximize his profit and therefore has an interest in keeping his production level high. If the group does not cooperate in holding production levels down, the price levels may drop, reducing the profit of the individual participants. Therefore, individual OPEC participants may cheat on the agreement to limit production in order to increase their own revenues and profits.

The unit commitment problem with independent entities controlling generating sources is similar in structure. It is a multi-party, multi-objective situation. Each source entity will wish to maximize his profit, but if there is no cooperation in generation scheduling, the system and consequently their market will not function correctly. Therefore, some means of solution has to be found to coordinate unit schedules to provide sufficient capacity for load following and provide spinning reserves adequate to handle unexpected load changes and outages which suddenly remove generating capacity.

One possible solution is to require the larger GENCOs and IPPs to provide the required spinning reserves for the entire system under the control of the TRANSCO. Other participants could be charged for this service with payments flowing through the TRANSCO to the GENCOs and IPPs.

Another approach would be to develop a new basis for establishing unit commitment based on multi-objective function theory and trade-off techniques. This is not a solution, but is a suggestion for further analytical effort.

2.4.2 Generation Dispatch and Load Following

Present generation system controls establish minimum cost dispatch schedules based on incremental production costs. Units under economic control are allocated participation in demand changes on an economic basis.

With a few new sources the utility can continue this practice. Non-utility generation secured under new source bidding could be required to participate as an essential requirement for bidding. Smaller QFs and IPPs could dispatch independently.

With no vertically integrated utility in the later scenarios, the technical problems associated with dispatching are broader. The control center for the system needs methods and economic models for controlling VARS, reserve service and regulating duty, and for allowing generation dispatch shifts for security and transmission scheduling. The basic economic structure without the utility is similar to a "zero sum game" in that these services are necessary for reliable system operation, but only the generating entities are participating. Any costs and payment determinations made by the TRANSCO control center in scheduling and dispatching must originate from funds provided by these participants. Ultimately, of course, the costs will be transferred to the DISCOs and retail customers.

Within the operating control environment some basis for these cost transfers must be found. One solution would be to incorporate provisions for recovering these costs in the rates for providing transmission service to the generating entities by the TRANSCO. The funds would then be reallocated amongst the generating entities as compensation for providing these services.

Any solutions will require additional hardware for monitoring generation, metering energy flows, and communications to the control centers. Billing and control center transactions costs will increase. Additional personnel, software, and computer hardware will be required.

2.4.3 AGC Systems

Current AGC systems would be adequate in Scenario 1. In Scenarios 2 and 5 the introduction of retail wheeling on a larger scale complicates the AGC problem in that the loads are effectively removed from the local utility service territory. Flows into the load are similar to interchange flows over tie lines. With a few retail wheeling arrangements, the current AGC system can be expanded to accommodate these retail wheeling contracts.

New sources engaged in supplying power to the local utility may complicate the AGC system if the sources are located outside of the local utility control area.

Their input into the system would be treated as a scheduled interchange. If they are inside the area, they may be treated as utility generation for AGC purposes.

In later scenarios, the AGC system concepts will probably need revision. The existing control areas are defined on the basis of utility service areas. These vanish in later scenarios. They could be replaced by using the TRANSCO's service territory to define the control area. All generation within the geographic area would be required to be under AGC control unless off-control operation (i.e., independently fixed schedules) were allowed by contract or the TRANSCO operators. System operators could establish sufficient generation levels under AGC system control to maintain interchange schedules between TRANSCO areas. If TRANSCOs are not the basis for redefining control areas, then source-load configurations will be. Areas will be defined electrically rather than geographically.

Maintaining control over tie-line flows is essential to the operation of the interconnected systems. If it is lost in any industry reorganization, tie flows, loop flows, and inadvertent interchange levels will increase. Tie flows must be controlled as all other flows must be, to prevent the overloading of the circuits and permit orderly transmission system scheduling.

TRANSCOs must have the ability to control generation levels to the extent necessary to schedule the transmission system. Security must be maintained.

2.4.4 Generation Planning and Capacity Reserves

Utility planners can use QF and IPP plants in determining reserve requirements. Uncertainties abound with regard to the actuality of these plants in the current situation. They would remain under Scenarios 1 and 2.

In Scenario 3, the utility planners will be in position to specify needed capacity to be bid on by GENCOs and IPPs.

In the last two scenarios the TRANSCO staff would have oversight responsibilities for securing adequate installed generation reserves. Two possible arrangements appear feasible.

1. The TRANSCOs provide transmission services and act as power brokers. In this case they assume responsibility for securing adequate generation supplies including required capacity reserves.
2. The TRANSCOs supply transmission services only. Adequate generation capacity reserves are then established by contract between the generating entities and the DISCOs and retail customers.

2.4.5 Solution of System Engineering Problems

In the last three scenarios, the responsibility for solution of system engineering problems would have to be established on the basis of contracts between all sources and the TRANSCO and DISCO. The TRANSCO would act as a service organization. GENCOs and IPPs would be required to participate as a condition of entry.
Since the TRANSCO costs would be passed along to both sources and load entities, the TRANSCO could seek minimum cost, technically effective solutions similar to the current basis for solving these problems.

The types of system engineering problems caused by new sources include breaker short circuit duties, stability and dynamic problems, voltage control, coordination and reliability studies, etc. The study and solution of these problems would be the responsibility of the TRANSCO's engineering staff with cooperative efforts required by all entities. Solutions to these problems involve hardware and operating procedures. For example, stability may be improved by adding generator stabilizers, improving transmission systems, revising plant control systems, using fast run-back operating methods, adding series capacitors, etc.

Another specific system engineering problem which must be addressed is that of the participation by all parties in emergency operations planning and implementation. If a system is in an emergency state the TRANSCO must be in control of the restoration. The TRANSCO staff should assume the role of current utility staff in emergency planning, operations, and system restoration.

The same conditions requiring participation in this system engineering area should be imposed on QFs and IPPs under the earlier scenarios. In these cases, the utility has the lead role in coordinating plans and procedures.

2.5 TECHNICAL ANALYTICAL ISSUES

The technical problems raised by the new sources of generation and the contractual terms which may be required in non-utility generators include analytical issues which should be addressed prior to implementing any major industry restructuring. This section recapitulates and summarizes those issues.

These are technical issues that are currently either not significant because present industry procedures are satisfactory or issues which do not have solutions applicable under conditions of some of the future scenarios. They should be considered prior to implementing the more extreme departures from the current structure outlined in Scenarios 4 and 5. They are all related to the non-utility generating sources.

2.5.1 Security Based Dispatch

The definition of transmission capability, discussed in the next chapter, is related to the issues involved in the reliability criteria used in scheduling and dispatching generation. Security levels are currently based on worst case analyses that are designed to avoid cascading failures. An analytical issue raised by this, is the investigation of the appropriateness of this type of criteria. The occurrences of widespread system failures are so infrequent that no reliable statistical basis exists on which to judge the merits of this technique versus others.

An investigation of alternative methods would seem to be fruitful. Reliability criteria based on probabilistic analysis may offer a more uniform level of security and allow greater freedom in generation scheduling. This idea has not been carried over into practical application because of the success of current methods.

2.5.2 Overall Economic Effects

The increased level of non-utility generation and required wheeling will affect the overall cost of generation. It is not at all clear what costs would result since non-utility generation may not be dispatchable and may not be controllable under utility unit commitment scheduling. In earlier scenarios, utility generating costs may increase if, for example, they must remove their larger, more efficient, units during light load periods to allow non-utility generation to operate.

An analysis of the potential overall economic effects could be accompanied by the analytical investigation of economic means for paying non-utility generators for the right to control or temporarily suspend their operations for economic dispatch and scheduling.

2.5.3 Unit Commitment Scheduling

As previously noted the unit commitment problem in the last scenarios is another analytical issue which requires attention. Present methods based on minimum total production cost may not be suitable for an environment with multiple generating entities. New criteria and techniques need to be developed that will balance the interests of all parties and result in feasible operating schedules.

In this same area, an analysis of the economic basis for paying new sources for the right to schedule their generation may also be needed.

2.5.4 Economic Framework for Non-Traditional Generation Services

In the generation dispatching area an economic framework for paying for reserve service, voltage support services (i.e., VAR generation) and the ability to control generation for system security and transmission system scheduling is needed. Present dispatching and generation scheduling methods do not consider these services. Costs for these non-traditional generation services are born by the utility at present. Whatever non-utility generation exists is generally not scheduled by the utility control center under economic terms.

2.5.5 AGC System Design

AGC system alternatives should be examined and expected performance analyzed under various conditions. The current scheme, based on a clear definition of control areas, is expandable to include new generation sources under the first three scenarios. The separation of the industry into segments under the last two scenarios implies a large number of competing generation entities and makes the definition of a control area less clear. In theory, the control area could be defined in terms of loads and sources, but with very many parties involved, the proper functioning of the current design of AGC becomes less clear and should be investigated to determine if current designs are appropriate under conditions of Scenarios 4 and 5.

CHAPTER III

CHAPTER 3

INCREASED TRANSMISSION ACCESS AND WHEELING

3.1 WHEELING AS AN ISSUE

Utilities generally design and use their transmission systems to deliver power from their own sources of generation to their customers. They also design and operate transmission for economic interchange among utilities and reserve sharing. In power pools, power broker arrangements, and where interchange transactions are arranged, the network provides wheeling for pool members, external utilities and independent generators.

Recall the definition in Chapter 1, Section 1.1:

> "Wheeling - The use of the transmission facilities of one system to transmit power of and for another entity or entities."

There are subclasses of wheeling. Two given in Chapter 1 were:

> "Wholesale wheeling - The wheeling of power and energy for delivery to utility system."
>
> "Retail wheeling - The wheeling of power for delivery to a retail customer."

Arrangement for the transmission of power generated by a utility or non-utility generator to a local or remote utility is wholesale wheeling. The transmission of power from a remote utility, or a non-utility generator regardless of location, to a retail customer is retail wheeling. These distinctions have technical effects. Retail wheeling may effectively remove the load from the local utility's service territory, displacing local utility generation and effectively increasing the scheduled net interchange by the amount of power wheeled to the retail customer.

This definition of wheeling also includes simultaneous buy-sell transactions. These are very common. For instance, in 1986 one large utility formally wheeled over 2 million MWh but also wheeled almost the same amount of energy under simultaneous buy-sell transactions. To put this in context, Consolidated Edison's 1986 sales to its customers in the New York City area amounted to about 30 million MWh.

For convenience, three roles in wheeling are referred to: the seller, the wheeler, and the buyer. Often the same entity fills two of these roles, or several entities jointly fill one of them.

3.1.1 Wheeling Practices

Most wheeling in the U.S. and Europe is a negotiated rather mechanical application of flat ($/kwh delivered, independent of mileage) or posted rates. In many countries the rates and levels are not public. In the U.S., the structures and levels are filed with the Federal Energy Regulatory Commission (FERC), but there is usually little indication of exactly how the conditions or numbers were determined.

In England, Parliament required that England's CEGB (Central Electric Generating Board) provide posted or flat wheeling rates. This was done, but they seem to be set at such a high level that no wheeling is occurring.

In New Zealand, the Labor government which took office in 1984 turned the government-owned generation and transmission utility into a somewhat independent corporation. It has construction, marketing, and production business units which it considers profit centers. It treats the transmission business unit as a cost center and will "facilitate access by competitors to its transmission system on fair and open terms" ("Statement of Corporate Intent, Electricity Corporation of New Zealand, Limited," June 1987). As of early 1988, how this was to be done had not been defined.

It is difficult to learn how the rate levels are determined because most are negotiated in private. However, abroad as well as in the U.S., at the beginning of the negotiations:

- the wheeler has some indication of its actual cost of wheeling, and
- the buyer and seller have some indication of the value of the benefits they will receive from the wheeling.

For wheeling to take place, the parties must negotiate a wheeling rate level which is above the costs and below the benefits.

When all parties are regulated utilities, common formulas for sharing the operating benefits of wheeling are:

- The wheeler has a fixed $kW or $/kWh ("postage stamp") rate, and the buyer and seller share any savings above that amount, or
- 15% of the buyer and seller savings are paid to the wheeler, or
- simultaneous buy-sell, where the wheeler buys at a price midway between its and the sellers' incremental costs, and sells at a price midway between its and the buyers' incremental costs.

A major obstacle facing a wheeling utility in the determination of the actual cost of wheeling is how the imbedded costs of existing transmission capital are to be handled. There are many ways this could be done. Commonly observed patterns are:

- if a firm service is provided, transmission capital cost is often included.
- If an interruptable service is provided, transmission capital cost is not included.

One fact about today's wheeling practices dominates all others. It is that almost all wheeling is voluntary and is to the mutual benefit of all parties. That is, there are enough economic benefits to each transaction to allow them to be shared. And the parties trust each other, so to a great extent operate on the basis of gentlemen's agreements which would be very difficult to enforce precisely.

3.1.2 Difference between Supplied and Delivered Power

The difference between what is supplied and what is delivered is a central issue in wheeling. Attributes of electricity include:

> Power (and its integral over time, energy): inevitable electrical losses occur when power is wheeled. (These losses are positive but incremental losses can be negative if wheeling reduces network flows.)
>
> Voltage: this tends to fluctuate more, and less controllably, far from generating units. VAR or reactive power is also absorbed or created by the transmission network.
>
> Frequency: physics dictates that the fundamental frequency changes synchronously everywhere in an ac interconnection. But harmful higher-frequency harmonics can be created (by arc furnaces, for instance) or absorbed (e.g. by filters) locally.
>
> Reliability: the frequency, duration, and predictability of outages differs from point to point in the network. Today's utility structure provides redundancy so that the fairly-frequent outages of individual generating units rarely cause a customer to lose power.
>
> Variability and controllability: electricity users want real-time control over their use of electricity. They want to be able to add or drop load at the flick of a switch. Electricity generators prefer to maintain constant production, and that load increase or decrease production in response to any operating conditions the generators face.

All of these attributes of electricity are affected by the network. They are all different at point of supply than at point of delivery. For some attributes, the electricity as delivered is better than the electricity as supplied; for other it is worse. For example, service reliability as perceived by a customer is usually greater than the availability of a single generator. And a buyer of electricity can usually vary his "take" much faster than a generator can vary its output. But voltage is more readily controlled at a generator bus than deep in a distribution network.

Today's utility industry has mechanisms to reduce the negative effects of the network, and to exploit the positive ones. In deregulation, with new wheeling structures, it will be important to develop new mechanisms for pricing, costing, providing, and controlling these effects.

3.1.3 Possible Problems and Solutions

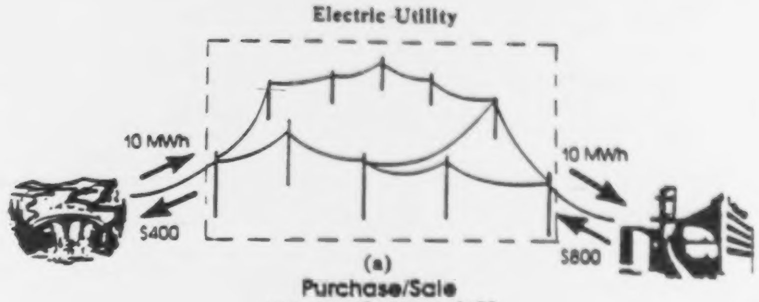
The balance of this chapter discusses a number of possible problems which increased transmission access and wheeling may bring. Many of these problems have to do with controlling the effects of the network on the attributes listed above. Effects of new generation sources alone, which do not necessarily have to do with wheeling, were discussed in Chapter 2. There is a great deal of overlap, however between technical problems related to the new generation sources and those related to transmission access and wheeling.

Issues of concern in this chapter are in three heavily-overlapping categories. One set of effects is mainly due to contracts and regulations. A second, referred to as "operating and planning problems," requires application of existing methods or knowledge. This application may involve variations on standard approaches, but nothing fundamentally new is needed. The third area requires new conceptual thinking as well as development of new tools and methods.

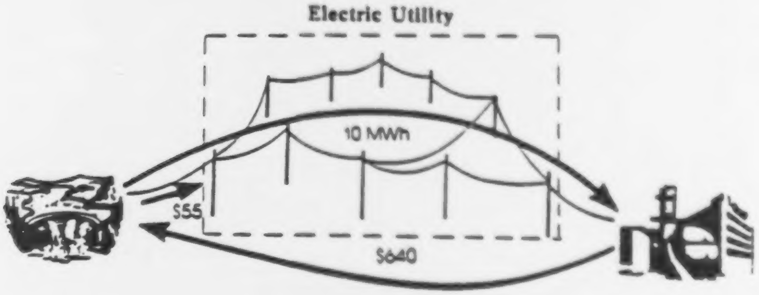
3.2 POSSIBLE EFFECTS OF CONTRACTUAL ARRANGEMENTS

3.2.1 Money Wheeling

Wheeling usually involves changes in energy flows over a transmission system. But it's possible to "wheel money," instead of wheeling power. For example, in Figure 3.1 (a) a utility buys power from an independent generator as well as producing it at its own plants. It sells to many customers. In Figure 3.1 (b) the utility wheels the power from the generator to one of the customers. But this wheeling transaction does not change any power flows: the generator continues to generate the same amount and the customer continues to draw the same amount of power. This wheeling contract itself has absolutely no physical effect: money is being wheeled; energy is not.



(a)
Purchase/Sale
Utility buys 10 MWh for $400
and sells 10 MWh for $800



(b)
Wheeling
Buyer pays seller $640 for 10 MWh;
seller pays utility $55 for wheeling
service (including losses).

Figure 3.1 - Wheeling is Physically the Same as a Simultaneous Purchase/Sale, So Sometimes a Wheeling Transaction Only Wheels Money, Not Energy.

Source: H.M. Merrill and F.C. Schweppe, "Wheeling, A Primer for Engineers," Transmission & Distribution, October 1987.

3.2.2 Loop Flows

In Figure 3.2, some of the transacted interchange between Systems A and B flows through System C. This utilization of the transmission of other systems for interchange schedules is often called loop flow, parallel flow, or circulating power flow. It is a phenomena of interconnected operation and is an inherent characteristic of ac power systems.

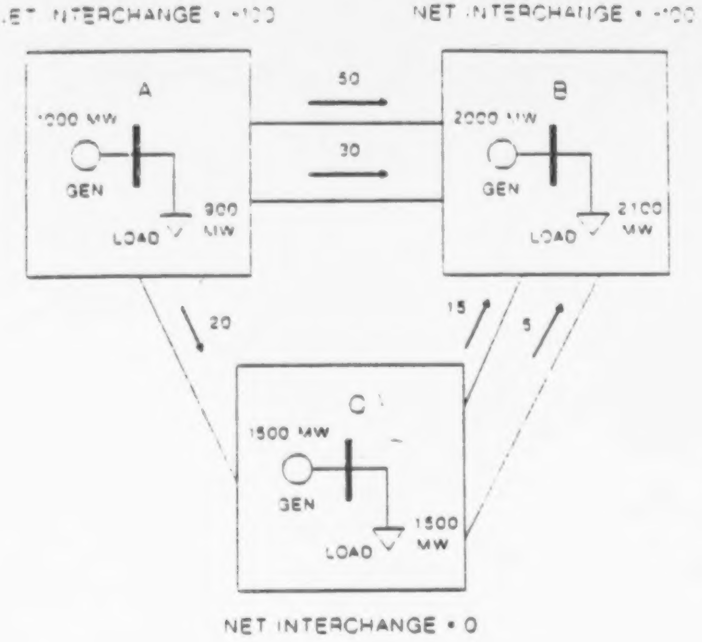

NET INTERCHANGE = +100
NET INTERCHANGE = -100
A
1000 MW
GEN
LOAD
900 MW
50
30
B
2000 MW
GEN
LOAD
2100 MW
20
15
5
C
1500 MW
GEN
LOAD
1500 MW
NET INTERCHANGE = 0

Figure 3.2 - Three Interconnected Systems

Loop flows among interconnected utility systems are usually not considered wheeling. These flows have traditionally been ignored unless they cause difficulties in the systems not party to the transaction. They are accepted as one of the unavoidable, undesirable effects of interconnection. However, as transactions and loop flows are increasing, some actions are being taken.

Some years ago, the most bothersome United States loop flows were around the "Western Doughnut," the transmission network linking the Pacific northwest and southwest. Nevada was the doughnut hole; there was strong north-south transmission through California and weaker transmission through Idaho, Utah, and Arizona. When large blocks of power were wheeled from the northwest to southern California, loop flows caused excessive network loading east of Nevada. The network has been strengthened, but loop flows still constitute a significant problem in the west.

With increases wheeling in recent years, the loop flow problem has become more widespread. For example, the Pennsylvania-New Jersey-Maryland interconnected companies (PJM) recently complained that perhaps 40% of a New York utility's purchases from Ontario Hydro were flowing westward through Michigan and the northeast through PJM. (See Figure 3.3.). Also, some western New York power flows through Pennsylvania. It was agreed that the New York Power Pool would (1) pay for the use of PJM's transmission and (2) install a phase angle regulator to control flows through PJM. New York has the right to use up to 400 MW of Pennsylvania Transmission through about 1993, and declining amounts thereafter.

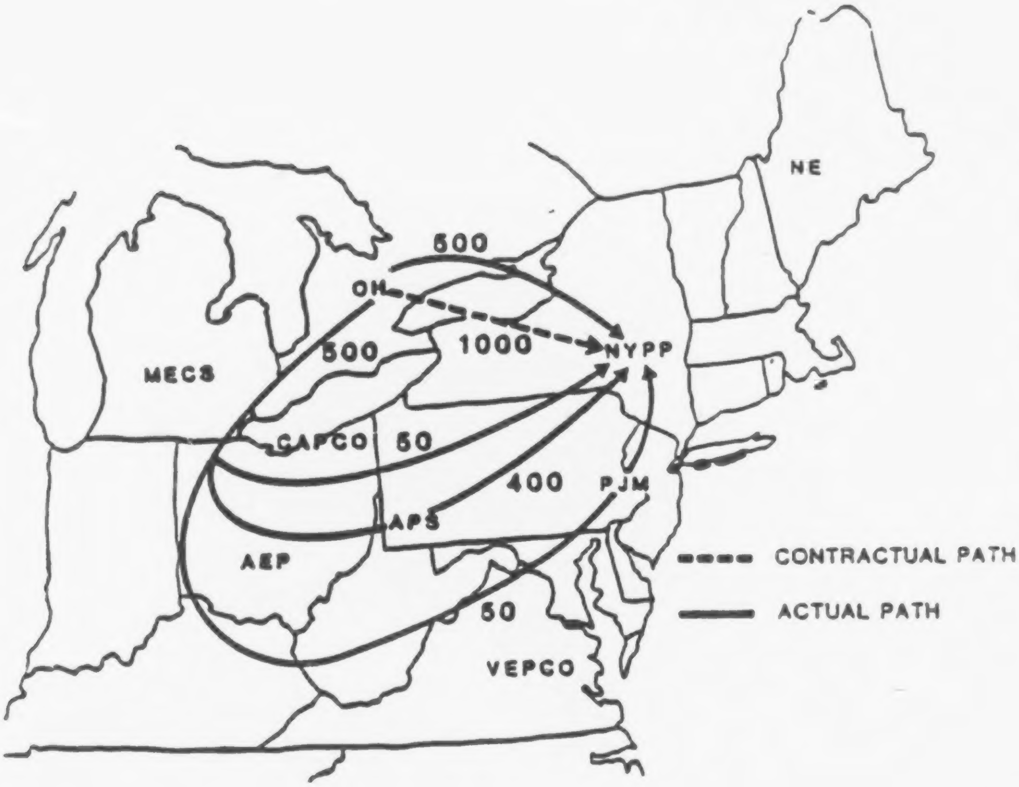


Figure 3.3 - Loop Flows When 1000 MW of Ontario Hydro Power Is Wheeled to Eastern New York

Source: R.M. Maliszewski, American Electric Power Service Corp.

3.2.3 Contract Types

Figure 3.4 summarizes some of the contract elements which reflect time and operating conditions. Each class of contract implies a different level of reliability and use of the network, so each generally has a different price.

- **FIRM CONTRACT**: Wheeler guarantees to provide wheeling services. Contract specifies conditions such as:
  - Rate Renegotiation Interval (how often rates are renegotiated, based on system conditions), for example:
    - Annual
    - 24 hour
    - 1 hour
  - Period Definition (when rate renegotiation interval is not specified)
    - Flat Rate (no time differentiation)
    - Time of Use Rate (hours within day, day of week, season of year)
    - Penalties for curtailment by the wheeler.
- **INTERRUPTABLE CONTRACT**: Wheeler provides wheeling service subject to availability of network capacity. Contract specifications include rate renegotiation interval or period definitions.
- **RESERVATION CONTRACT**: Wheeler agrees to provide wheeling service if buyer and seller want to use it.

Figure 3.4 - Contract Elements which Reflect Time and Operating Conditions

Figure 3.5 summarizes some of the different ways network flows can enter into the specification of wheeling rate structures. In general, it can be shown that the megawatt-mile approach is a special case of the marginal cost approach. The contract path approach is a special case of the megawatt-mile approach.

The rate level is of prime importance in establishing the desired wheeling rates. The rate level determines how the long term costs and benefits of wheeling are shared between the wheeler, the seller, and the buyer. Figure 3.5 lists various types of wheeling rates and their parameters.

- **POSTAGE STAMP**: Rate does not depend on network flows or distances
- **CONTRACT PATH (RED LINE)**: Rate depends on specified nominal path through network (sometimes drawn with a red pencil!)
- **MEGAWATT-MILE**: Rate depends on line-by-line results of load flow analyses. Three different approaches.
  - Net Effects (consider both increases and decreases in line flows)
  - Positive Difference (consider only increases line flows)
  - Vector Difference (assume an empty system with no other flows)
- **MARGINAL COST**: Rate based on marginal costs of wheeler as determined by load flows. Includes two types of costs:
  - Losses
  - Quality of Supply (costs of system reliability)
    - Line Overloads
    - Cost of New Lines

Figure 3.5 - Different Ways of Reflecting Network Flows in Wheeling Rates

The most prevalent structure is the postage stamp rate, followed by the contract path (redline)*. Both have been accepted by FERC. Most wheeling in the U.S. is short-term. Wheeling through several utilities along a contract path may be done using a postage stamp for each utility. The megawatt-mile method is presently being used in Texas and is receiving increased interest (e.g., in California) because of pressure for mandatory open access to the transmission system. There are no known situations where the most general marginal cost procedures are actually implemented. Practical details (including FERC acceptance) still need to be worked out, but studies of their implications are under way in the U.S.

3.2.4 Effects on Operations

Different wheeling contracts can effect system operations in different ways. For example, Figure 3.6 is a simplified representation of a situation where two potential sellers compete for a sale. In the area in question, wheeling contracts are by contract path. Utilities A and B both want to sell to the buyer. Both would have had to wheel through essentially the same intermediate utilities. Because of pre-existing commitments, seller B was able to assemble a contract path, while A was not. Assuming coal is cheaper than gas, the overall economics would probably have been better had A been able to do so -- which would have happened with different procedures for acquiring wheeling rights.

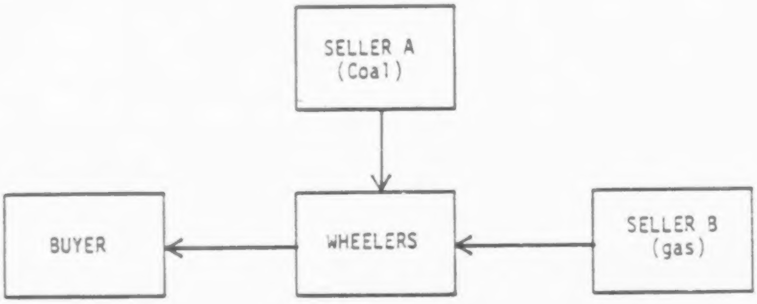


Figure 3.6 - Two Sellers Competed to Wheel Power to a Buyer

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* See "Terms and Conditions of Existing Transmission Service Agreements and Tariffs," Edison Electric Institute, Washington, D.C., December 1984.

As another example, one contract provides two ways of calculating wheeling rates. The transaction can be treated as a simultaneous buy-sell by the wheeler, which collects approximately 50% of the spread between the buyer and seller incremental costs, with the buyer and seller essentially splitting the rest. Or it can be treated as a wheel, with the wheeler charging only 15% of the spread between purchaser and seller.

The contract allows the buy-sell option only when the wheeler has generating capacity that could be backed off to accommodate the purchase. When it does not, the transaction must be treated as a wheel. The wheeler has obvious incentive to avoid operating conditions where the 15% rate applies.

One active wheeler provides transmission capability at a fixed rate for a contracted amount of capacity. The charges do not vary if the buyer and seller reduce the amount wheeled for a period of time. This means that buyers and sellers have an incentive to wheel at close to their contracted amounts. Their generation patterns would probably be different could they pay only for the MWh actually wheeled. But this flexibility would affect the wheeler's ability to sell network access to other parties.

3.2.5 Contractual Effects on System Evolution

In some areas utilities can reserve wheeling capacity at relatively low rates, paying additional charges if they actually wheel power. This facilitates transactions where a utility with excess generating capacity sells reserves to a deficit utility. Being able to make reserve transactions allows utilities to take turns adding capacity in relatively large blocks, taking advantage of presumed economies of scale.

In Texas this is harder, and utilities are more likely to meet their reserve obligations with smaller increments of their own capacity. This is because Texas uses a megawatt-mile method for wheeling rates with no provision for reservation contracts. This means that utilities which want to traffic in reserves must pay for wheeling service even if they never use it.

Each of these patterns of system expansion has its own advantages: one is cheaper, the other more flexible. The salient point here is that the wheeling contracts influence which of them a utility chooses.

3.3 POSSIBLE OPERATIONAL AND PLANNING PROBLEMS

Problems in applying today's operations and planning methods under increased competition and deregulation are discussed in this Section. The emphasis here is on problems which must be solved with extensions or modifications of existing methods. These problems include:

- maintaining adequate real-time control,
- solving a variety of scheduling problems,
- maximizing the use of the network,
- planning network additions,
- solving certain system-wide problems, and
- developing and applying emergency procedures.

In Section 3.4, other technical problems, which seem to require some new and different approaches, are discussed.

Both sections talk about problems that have not yet been solved. We suspect that they are solvable.

3.3.1 Real-Time Control

Need for Flow Control

Transmission line flows must be maintained within the line ratings and, in general, flows must be kept within secure operating limits. If the network is heavily used, this means that inadvertent interchange must be kept at low levels.

Generation shifting is the most common way to allow for system security in the general sense in ac systems control. Another way is circuit switching - but this is usually not done because it tends to reduce security. A third way to control flows is to control load. Again, this is not practiced widely.

Need for Generation Control

Since controlling transmission flows usually means controlling generation, methods for accomplishing this are discussed under various scenarios. For convenience, relevant portions from the scenario descriptions are repeated.

Under Scenarios 1, 2, and 3, the buyers and sellers become somewhat independent of the utility they happen to be connected to. Existing AGC systems allow interconnected utilities to operate independently, yet in coordination. Each utility operates as a control area, and is responsible for matching generation to load within its area.

Coordination of interconnected operations is through several media. One is the telephone: operators of neighboring systems talk very frequently, perhaps hourly or even more often. A second is automatic generation control (or as it used to be called tie line bias control.) This requires metering flows on each tie line and sending data in real time to the computers of the two control areas the line connects.

If loads and generators become independent under retail wheeling contracts, they can in concept become separate control areas. This will require some additional metering and telemetry for the AGC. It will also require some additional telephone communication. Neither presents a theoretical problem. But if the number of metering points or telephone calls becomes large, utility control centers will need upgrading, and more dispatchers may be needed. And there is not 100% reliable way to accomplish this electronic removal of loads.

In Scenarios 4 and 5 (and to a more limited extent in Scenarios 1-3), especially as the amount of power bought, sold, and wheeled increases to significant levels, present AGC concepts become strained.

In particular, an individual IPP or QF might wheel power to an individual customer. Each could constitute a control area. But they are much less able to hold to a constant interchange schedule than are normal utility control areas. Possibly telemetry could keep the seller informed about the buyer's instantaneous load. But generating to match that load could be impractical for the seller.

If the seller tripped for some reason, telemetry in the other direction could inform the buyer, who could trip his load as well.

This would clearly be an unattractive way to operate. To avoid this, present AGC concepts could be extended to allow non-contiguous control areas, different applications of the concept of inadvertent interchange, and trafficking in variability and controllability.

For example, suppose a generator and a load, both within a utility's service territory, enter into a transaction involving wheeling through the utility. The utility's AGC could treat them like a single external utility. The line to the generator and the line to the load would be tie lines. Of course, it would be difficult to control the generator to exactly match the load, so there would be considerably more inadvertent interchange than a utility normally deals with. Perhaps payments or penalties would need to be provided for generators that track the load well or poorly.

Loss of Control

Lack of control over line flows may cause overloaded lines or stations. It will increase inadvertent interchange. If it gets too bad, it will require mandatory corrective action or rates for payment in dollars by offending parties. This requires methods for determining who the offenders may be.

The control center in Laufenburg, Switzerland, performs some policing of interconnected utility operations over much of western Europe. There is no national control center with this function in the United States. Instead, problems are identified by individual utilities, or sometimes through NERC activities. This policing role would have to be assumed by some entity or entities under the more extreme scenarios.

Proper voltage control is essential to system operation - but represents a cost to whomever provides it when separate voltage control devices are used. Lack of control causes poor voltage profiles. In the extreme, this could result in poor customer voltages if local voltage control devices are out of control range. In very extreme situations this could cause a system voltage collapse if VARs start flowing to support MW flows, which in turn cause further voltage declines. Again, some entity or entities would need to coordinate voltage control. And the embedded cost of existing devices, as well as the cost of new ones, would have to be allocated among those who benefit.

3.3.2 Scheduling Problems

Scheduling is concerned with a time frame greater than an hour and less than a year or so. It includes forecasting, shutting down and starting up generating units (the unit commitment problem), scheduling fuel and hydro resources, maintenance scheduling, and scheduling wheeling, purchases, and sales. Scheduling also includes assessing network capacity; this is discussed in Section 3.4.

Wheeling transactions that are under utility control are options which utilities can consider as they plan operations. Existing methods for unit commitment, maintenance scheduling, etc., may need to be modified if wheeling increases. This is because these methods are not now able to include wheeling as alternatives. If wheeling transactions are uncertain, and the uncertainties are significant, fundamental new approaches to solving operations planning problems will need to be developed.

One issue which will have to be resolved is providing even-handed treatment to utility-owned resources and independents as they compete with each other. This would be a particular problem in Scenarios 3 and 4.

Some of the challenges described above depend on the extent of wheeling and transmission access. Things work (although there are strains) at today's levels. If wheeling and transmission access increase, the strains will become more troublesome.

For instance, there are many wheeling transactions, especially wheeling transactions whose levels change frequently, the wheeling utility may have to train and add more personnel just to handle the interchange rescheduling. This has already happened to at least one utility in the United States: Houston Lighting and Power has added an energy scheduler to the dispatch staff. That utility estimates that over one-half his time is dedicated to handling the effects of cogeneration on system operations. The utility anticipates staffing about five additional people in the future to accomplish this function for all shifts.

3.3.3 Maximizing Network Use

Generation Shifting

The first and easiest mechanism to allow increased transmission system use for additional wheeling flows is to shift generation, when required, to alleviate transmission overloads. This is done occasionally in the United States. European practice is to reduce the wheeling instead. Constrained economic dispatch programs or optimal power flow programs are used in the New York Power Pool and elsewhere to shift generation in real time for security dispatch purposes.

Redispatching to recognize constraints causes the wheeling utility's operating costs to go up. These increases are fairly well-defined and are not hard to compute. It is reasonable to expect the buyer and seller to cover these costs.

It may also be appropriate to reduce third-party generation or other wheeling transactions in order to alleviate network overloading. This option is likely to be more important under Scenarios 3, 4, and 5 than under Scenarios 1 and 2. There are three conceptual problems in doing this. First, assessing the costs to the parties curtailed is not easy: they may include ill-defined opportunity costs. Second, this lack of definition makes it hard to define an optimal curtailment policy or method.

Third, as discussed in Chapter 2, this really is not an optimization problem but rather a problem with multiple and conflicting objectives.

Relaxing Security Constraints

Today, United States utilities have planning and operating procedures to avoid cascading outages under specified contingencies. Applying these procedures provides reliable electric service.

There is no indication that current reliability levels are unnecessarily high, but relaxing constraints, or fine-tuning them, could provide additional transfer capability. Some of these actions would reduce reliability; others would not. For example, the thermal rating or limit of a transmission line is based on stringent ambient conditions: hot day, little wind, etc. Often weather is more favorable, and the line has higher capability. A real-time thermal-rating method could increase transfer capability during much of a year, with no loss of reliability. There is obviously a limit to the amount of additional capability that can be provided before reliability suffers.

Relaxing or fine-tuning constraints may conflict with solving a problem discussed in Section 3.4: with increased wheeling, it is important to be able to objectively and simply define and measure transmission capacity.

System Reinforcement

A third important way to increase transmission capability is to add lines and other equipment to strengthen weak spots. Sometimes this can be done quite inexpensively. For instance, a study of a major pool found that transfer capability could be increased substantially by adding capacitors at certain substations. Capital and operating costs for doing this were low, and there was essentially no environmental impact.

Under other circumstances it is necessary to do more expensive things (which may be hard to do in a timely fashion), such as:

- add lines,

- upgrade existing lines,
- increase voltage levels,
- convert single circuit lines to double circuits, and
- provide dc or high-phase-order ac lines, etc.

3.3.4 Transmission Planning Problems

One major effect on planning is due to the great uncertainty in growth of non-utility generation. For example, Figure 3.7 shows the published forecasts of QF and IPP capacity issued by the WSCC region of NERC. The data show the forecasts for the total generation expected to be in service in 1992 by year that the forecast was published and the year to year variation in the forecast. The uncertainty presents a difficult forecasting situation for planning staffs of the utilities - reminiscent of the problem of forecasting loads as part of generation planning. It takes several years to construct new transmission facilities. If the QFs and IPPs actually do appear on the system, new transmission facilities may be required for wheeling. If the utility system construction is based on the early forecasts and the IPPs and QFs do not appear, the utility may have excess transmission capacity. On the other hand, if the planning engineers wait to see what QF and IPP generation is actually constructed, there may not be sufficient transmission capacity available for wheeling.

The cost of this uncertainty may be significant but would probably not be unbearable for an integrated utility (Scenarios 1, 2, 3) because transmission facilities are less expensive than generation plant and hence represent a small fraction of total plant. But in Scenarios 4 and 5 the transmission is owned by an independent entity and constitutes most of the entity's assets. Uncertainties, as a fraction of their total assets, may represent unacceptable risks.

The TRANSCO is assumed to have an obligation to provide an adequate and reliable transmission capacity necessary to supply the wheeling needs of anticipated customers. Regulatory authorities may require consideration and coordination of regional transmission capacity needs. Regulators may penalize TRANSCO as reliability is poor.

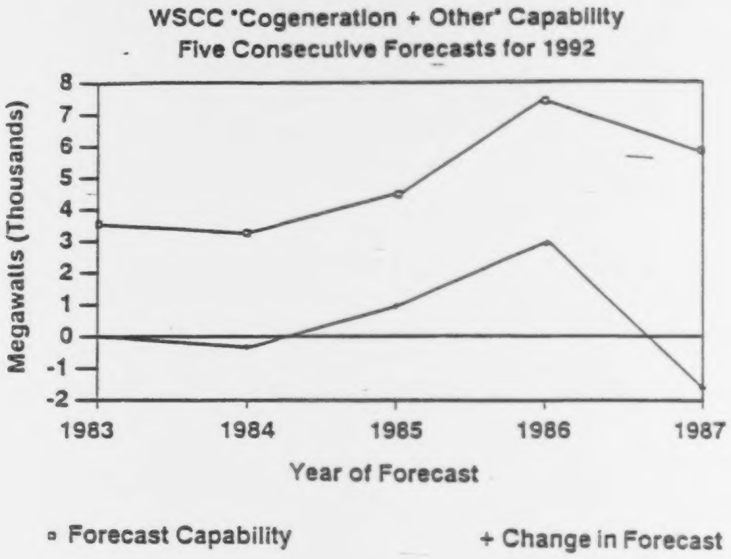

Figure 3.7 - Forecasts of Non-Utility Generation in WSCC. Upper curve is total capacity forecast. Lower is year-to-year variation on the forecast.

The TRANSCO would have less capital than an integrated utility serving the same area, and the uncertainty in transmission requirements could be burdensome.

The uncertainty could be reduced in all scenarios by providing a role in the planning process for the QFs and IPPs. Some institutional barriers would have to be overcome, as these entities will be in competition with the utilities and data exchange may not be as open as at present.

3.3.5 Solving System-Engineering Problems

Certain technical (e.g., stability, voltage-VAR control, etc.) problems involve broad system analyses. The resolutions of these problems are usually handled routinely by utilities today.

Some problems are not handled routinely today. For example, major transfers from one area to another may cause operating problems which could be rectified by network modifications in neighboring systems. If the neighboring utilities do not choose to make these changes, the transfers cannot take place. There is no convenient mechanism for one system to undertake internal improvements for the benefit of another. Certainly the ratepayers in one area do not wish to finance improvements for the benefit of another utility's customers. And a utility wanting to pay for improvements to another utility's system would have to overcome serious regulatory hurdles.

If the industry becomes more fragmented, this type of situation will be more common.

VAR-Voltage Control

The flow of VARs has two major effects on the transmission circuits and system. It uses up a portion of the physical capacity of the circuit, causing real power losses. It also effects the voltage magnitudes in the circuit. This later effect is complex and depends upon the exact circuit conditions. In some situations, VAR flow will cause the voltage to rise along the circuit. Sometimes the flow of VARs will cause a voltage drop at the receiving end. The rise or the drop may be beyond acceptable system operating standards.

VAR-voltage control is important for the overall system, but is achieved by devices or actions at specific locations. When a single utility owns and operates all generation and transmission facilities in an area, it takes action to solve this system problem. But in a fragmented system, none of the individual independent entities can solve its local problem: they have to work together to solve the system-wide problem.

This might be done by giving the transmission utility a way to charge for VAR-voltage support. In real time, the transmission utility could have authority to schedule generator VARs. But this is a difficult technical problem. Even today's fully integrated utilities seem to have problems with it.

System Stability and Dynamic Problems

Stability problems, and various types of dynamic problems, involve both generation and transmission systems. These are studied on a broad system basis today. This needs to continue, and requires a mechanism for data exchange and joint studies. Fixes are also coordinated efforts, and include fast run-back of generation, series capacitor installations, added switching stations, intermediate controlled supplies, generator stabilizer, etc. Operating fixes may involve controls or limits on power transfers.

Since both hardware and control fixes require cooperative efforts in study and implementation, a system-wide mechanism is needed. TRANSCOs should probably have the responsibility here under Scenarios 4 and 5 with authority established by contracts. Integrated utilities could continue to do this under Scenarios 1, 2, and 3.

3.3.6 Emergencies

Emergencies involve three time periods. Before an emergency occurs, preventive and limiting measures are taken. During the emergency, real-time responses take place. Afterward, the system is restored to normal operation.

In Scenario 1, utilities are responsible for actions in all three time periods. In the other scenarios, other parties are involved to varying degrees. But under all scenarios, it is important that actions be coordinated. This might appropriately be done by the utility in Scenarios 1, 2, and 3, and by the TRANSCO in Scenarios 4 and 5.

For example, relays and other kinds of protective equipment need to be coordinated. The approximate amount of load which needs to be shed if frequency decays by 0.05 Hz, for example, is known to the utilities. The under-frequency relays set 0.05 Hz value need to control, in the aggregate, the right amount of load.

The system operation function includes the authority for and capability of tripping generation and load, if needed, to prevent line overloading or system collapse. This function must continue even under deregulation.

Restoration is the problem of restarting a "blacked-out island." QFs and IPPs can be of benefit; they can also constitute a problem. Whether they make things better or worse is independent of whether they are wheeling, selling direct to the utility, or simply supplying their own load, connected in parallel to the utility.

One step in restoration is to provide electric power (to run pumps and other equipment) in blacked-out power plants. If QFs and IPPs can start in a blacked-out system, they can in theory provide this power. They also provide incremental load-carrying capability within an island. However, studies have shown that the most frequent problems in restoring service have to do with load and generation coordination. (See Table 3.1.) These problems will be increased by having to deal with non-utility operators, so utilities may discount QFs and IPPs as resources. The QFs and IPPs may even introduce additional switching and coordination complications, for instance if they need to be switched out in early stages of restoration and then switched in and synchronized later.

The significance of IPPs and QFs in system restoration has to do purely with the number and types of generation facilities in an island, and so is independent of any particular deregulation scenario. But authority and the means to use this authority will need to be provided, probably to the TRANSCO in Scenarios 4 and 5.

TABLE 3.1

Restoration Problems by Frequency of Occurrence

DESCRIPTION	NUMBER
Switching operation	8
Procedure out of date	7
Supervisory control/data acquisition inadequate	7
Dispatch office coordination	7
System status determination	6
Sustained overvoltage	5
Synchronization location and facilities	5

(Based on 48 major disturbance reports, cited in "Power System Restoration," IEEE Trans. Power Systems, PWRS-2, No. 4, Nov. 1987.)

3.4 ANALYTICAL PROBLEMS

Section 3.3 discussed transmission access and wheeling problems that involve presently-performed functions and that can be solved with relatively straight-forward extensions of today's methods.

In this section four problems are discussed that seem to loom over increased transmission access and wheeling and for which new solutions need to be found:

- definition of available transmission capacity,
- reliability and security issues,
- transmission scheduling, and
- costing, valuing, and pricing wheeling.

3.4.1 Definition of Available Transmission Capacity

How Transmission Capacity is Measured Today

There is no simple equivalent of the telephone company's busy signal on a power network. Transfer capacity is not the rating of a single line or a few lines. It is a function of the strength of the network as a whole. It is defined in terms of reliability criteria, which themselves are objective and somewhat imprecise. It varies as switching operations occur and as demand, generation, and wheeling patterns change. Even loop flows and actions taken by operators of other system affect the available transfer capability.

Figure 3.8 attempts to define how much power system X can transmit to system Y, with a simultaneous transfer from X to Z. For instance, the Y to X transfer capability is 6200 MW when X to Z transfer is 5200 MW. On the other hand, if the transfers are in the opposite direction, with Z transmitting 2600 MW to X, X can only transmit 1300 MW to Y.

Three such diagrams are required to represent transfer capabilities for a three area (X, Y, and Z) system. Each diagram is valid for one specific operating condition and a particular set of reliability criteria. These diagrams are developed using load flow programs, which simulate the flows on the network. Developing sets of these diagrams for even a three-area system, for a spectrum of operating conditions, takes a lot of engineering time and inter-utility cooperation. Transfer capabilities for systems with more complications (due to a variety of possible wheeling transactions, for instance), are much harder to model.

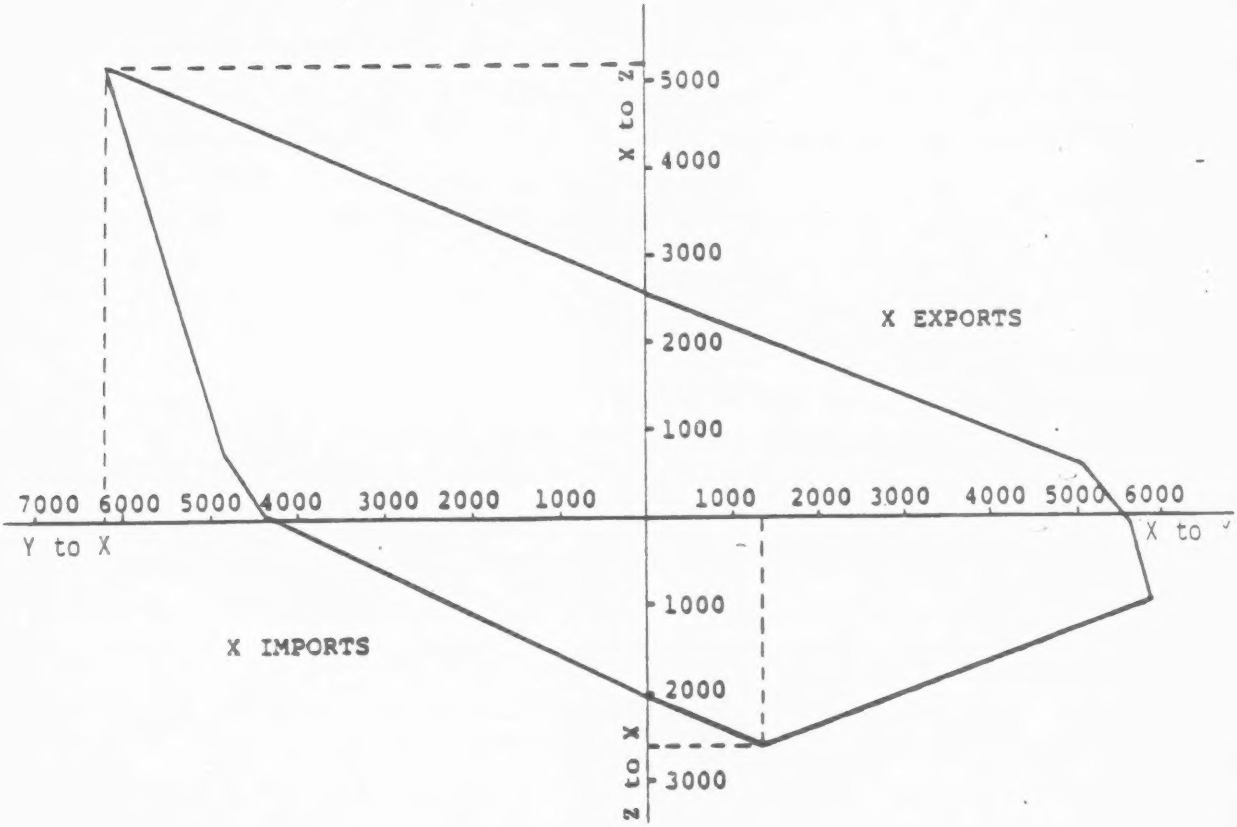

Figure 3.8 - Typical Bi-Axis Transfer Capability Polygon
Source:EPRI EL-3425

Effects of Increased Wheeling

Today's methods for measuring transmission capacity work, but only because

- the parties all have large engineering staffs,
- they are willing to exchange data and cooperate in studies, and
- they are not in serious competition, so utility-to-utility differences in defining transfer capabilities are not seen as competitive ploys.

Under the deregulated scenarios, particularly Scenarios 4 and 5, only the first of these conditions is likely to hold for the GENCOs. The TRANSCOs may have an adequate staff, but the cooperative nature of today's environment will be lost. Since under some of the scenarios the entity owning the transmission may compete with IPPs and QFs who want to wheel, the definition of transfer capacity may be a bone of contention. Accordingly, today's methods for measuring transmission capability will probably not work under deregulation and signs of this are already occurring.

What is Needed

Under deregulation and increased wheeling, a new method for defining transfer capacity is needed, with the following characteristics:

- it should require straight-forward calculations,
- it should represent an objective, defensible, standard,
- it should not be so conservative as to unduly limit wheeling,
- it should represent variations in operating conditions and network changes due to maintenance, switching, etc., and
- it should lend itself to on-line use in control centers as well as consistent application in planning.

It is particularly important that this method be so clearly acceptable to all parties that the courts and commissions will not have to spend inordinate amounts of time reviewing and redefining transmission transfer capability. Such a method is not available today. Some creative thinking will be needed to create it.

3.4.2 Reliability and Security Issues

Reliability and security issues are closely related to transfer capacity.

Today recommended criteria are developed by NERC, by each reliability area, and in some cases by power pools. The criteria are interpreted and applied by each individual utility. These criteria are different for different parts of the system. For example, reliability of satisfying expected loads by a utility's set of power plants is expressed as loss of load probability, expected unmet demand, reserve margin, etc. The reliability of the transmission network is defined in terms of the number and type of contingencies it is designed to withstand. There is no accepted method for expressing generation reliability and transmission reliability in equivalent terms.

Today's level of reliability is one of the bundled attributes of electricity. It is provided to the customer as part of a package by integrated utilities. Under deregulation, with this package unbundled, ways of measuring, equivalencing, costing, and pricing reliability and security will be needed.

3.4.3 The Transmission Scheduling Problem

With few exceptions, scheduling use of transmission capacity is not a problem today. If a utility has an internal bottleneck, and many do, it simply redispatches generation so as not to overload it. The costs are shared by all of the customers and are not perceived by them.

The few exceptions -- harbingers of what may occur under deregulation and increased competition -- involve multi-company transactions. Two examples involving loop flows were mentioned earlier in this chapter. When loop flows hit transmission constraints, attempts were made to negotiate ad hoc solutions. For the PJM problem discussed earlier, the solution included cash payments, and a modification to the network. Around the western doughnut, the negotiation continues.

Several methods have been proposed for scheduling around transmission bottlenecks. Schweppe et al have proposed methods based on marginal cost pricing theory (e.g., see F. C. Schweppe, R.E. Bohn, and M.C. Caramanis, "Wheeling Rates: An Economic-Engineering Foundation," MIT Laboratory for Electromagnetic and Electronic Systems, report TR 85-005, September 1985). The New York State Energy Research and Development Authority sponsored work which led to a similar but somewhat different solution involving bidding (H.M. Merrill, "Economically Efficient Allocation of New York's Transmission and Distribution System," Power Technologies, Inc., June 1985).

Figure 3.9 is an initial view of two dimensions of the transmission scheduling problem. Faced with two possible transactions, both of which cannot be accommodated, which should the TRANSCO accept? With costs known, this is a classical integer programming problem known as the knapsack problem.

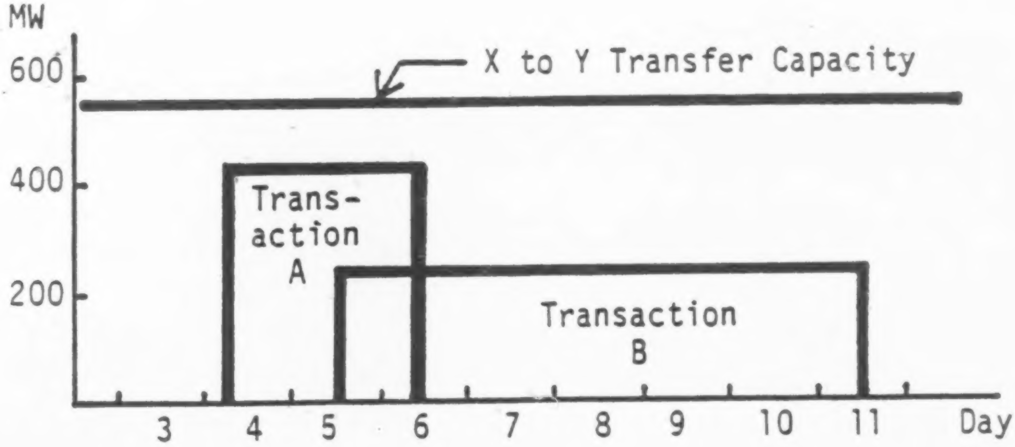

Figure 3.9 - Two Dimensions of Transmission Scheduling: Time and Capacity

This simplified problem is not very useful, however. In reality there may be many more dimensions, because wheeling can cross the network in a variety of paths. With wheeling to or from three entities, Figure 3.8 becomes a three-dimensional version of Figure 3.9, with time the third dimension.

The scheduling problem is further complicated by uncertainty. In Figure 3.9, the TRANSCO might prefer transaction B. But if A applies today, and B is anticipated but not guaranteed to apply tomorrow, should the TRANSCO turn down A and wait for B?

3.4.4 Costing, Valuing, and Pricing

Economic issues underlie the reliability and scheduling problems described above. These issues are somewhat beyond the scope of this report, which is on engineering topics. But the economics and engineering are so entwined that this discussion would be incomplete without raising these economic issues.

The utility industry and its regulators have developed a workable regulated monopoly where

- prices are somewhat but not precisely cost-based,
- the industry is close to but not economically efficient, and
- utility owners generally recover costs and earn an approximately fair return.

As was mentioned earlier, bundling a variety of services and charging for them as a package has made present pricing and regulation much easier than it would otherwise have been.

These services will be unbundled under deregulation and increased competition. But even under Scenario 5, the most extreme scenario, the industry will include regulated monopolies (TRANSCOs and DISCOs). This mixed market/monopoly system will present unusual pricing and costing challenges. One proposed approach is to charge for wheeling services on the basis of marginal costs (Schweppe et al, op.

cit.). This is attractive from the economic viewpoint. Methods are being developed to test and implement these ideas. But there are issues which present theory has not yet fully resolved, such as reconciling marginal cost pricing and revenue recovery. These methods are based on classical economic dispatch theory and would need to be rethought for applications in Scenarios 4 and 5. A long-term marginal cost theory may be needed in those scenarios: classical economic dispatch theory uses short-term marginal costs.

For example, Figure 3.10 compares short-term marginal wheeling costs and changes in wheeling utility operating costs for identical transactions wheeled through two utilities, A and B. Both A and B have transmission capital costs to recover.

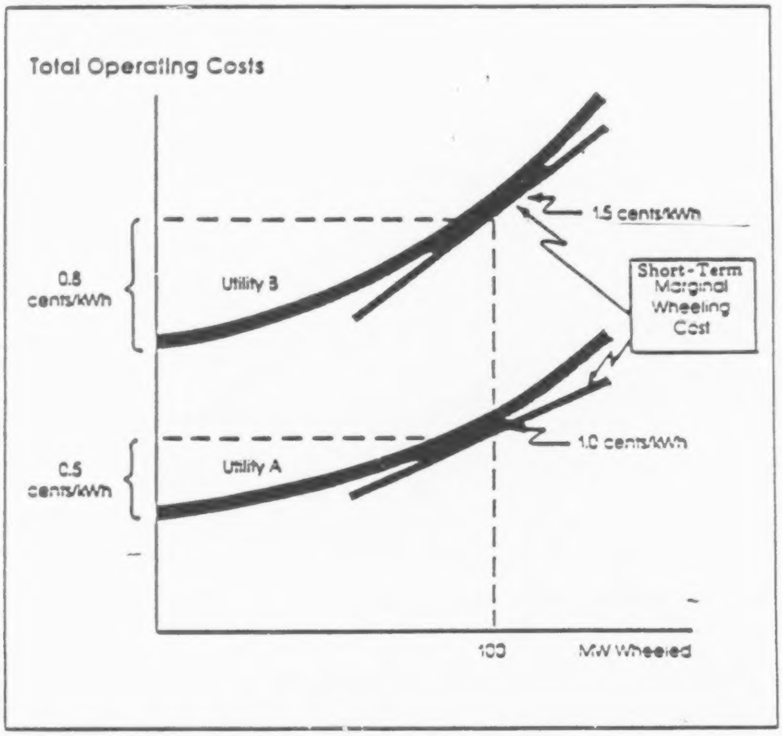

Figure 3.10 - Short-term marginal wheeling costs and changes in total operating costs, per kWh wheeled, for two hypothetical wheeling utilities

Source: Schweppe and Merrill, Op.Cit.

Table 3.2 shows that both transactions more than recover changes in operating costs caused by the wheeling. But, utility A under-recovers fixed costs, while utility B over-recovers.

TABLE 3.2

Transactions Involving Two Different Wheeling Utilities

	Wheeling through Utility A	Wheeling through Utility B
Wheeling rate (marginal wheeling cost)	1.0 cents/kWh	1.5 cents/kWh
Less:		
Total change in wheeling utility's operating costs	0.5 cents/kWh	0.8 cents/kWh
Change in net operating income to wheeling utility	+0.5 cents/kWh	+0.7 cents/kWh
Less:		
Fixed capital costs	1.5 cents/kWh	0.5 cents/kWh
Change in total revenues to wheeling utility	-1.0 cents/kWh (under-recovery)	+0.2 cents/kWh (over-recovery)

This can be fixed by adding "revenue reconciliation" to marginal costs. Unfortunately, this gives wheeling rates that do not always encourage an increase in production efficiency. For instance, suppose the marginal wheeling cost is 1 cent/kWh. Revenue reconciliation can be either positive or negative, depending on whether the utility would otherwise under-recover or over-recover. Considering utility A, which under-recovered, let the

Wheeling Rate = 2 cents/kWh (Revenue reconciliation of +1 cent/kWh).

Now suppose the buyer and seller are also utilities, with marginal operating costs of 6 cents/kWh and 4 cents/kWh, respectively. If the wheeling rate is the marginal wheeling cost of 1 cent/kWh, the buyer and seller can afford a deal which would increase overall production efficiency and cover the wheeling utility (A's) operating costs, but not its fixed costs. If the wheeling rate is 2 cents/kWh, the buyer and seller have no incentive to wheel even though doing so would improve overall production efficiency and recover A's fixed costs.

CHAPTER IV

CHAPTER 4

SUMMARY OF TECHNICAL ISSUES AND POSSIBLE SOLUTIONS

4.1 SUMMARY OF TECHNICAL PROBLEMS POSED BY SCENARIOS

The major specific technical problem areas which are affected by the increasing amounts of non-utility generation and requirements for wheeling are:

1. measuring transmission system capability,
2. ensuring adequate spinning reserves for the generation system,
3. maintaining adequate control of generation, frequency and interchange flows,
4. establishing methods for scheduling transmission use and controlling transmission flows,
5. planning the bulk power system,
6. system dispatching and operation, and
7. solving system-wide technical problems.

Note that this list does not include those technical problems and solutions associated with transmission system limitations that are due to inherent physical limitations. These were discussed in the first report of this sequence and reviewed briefly in Chapter 3. They will continue to exist and be solved by the methods discussed. The scenarios do affect the intensity and complexity of these transmission system limitations by the level of non-utility generation capacity in the first three scenarios, the shifting of responsibilities in the last two scenarios, and the growth of transmission access and wheeling in all of the scenarios.

The list of transmission system limitations and solutions is long. Existing technical problems and future ones are highly system specific. Engineering approaches exist to solve problems such as increased breaker short circuit duties, requirements for added capacity in lines, breakers and transmission networks, etc. The scenario conditions do not change the basic nature of these problems nor their solution.

They do change the economic framework and require the clear establishment of responsibilities in the different institutional structures.

4.2 MEASURING TRANSMISSION SYSTEM CAPABILITY

Under the present, cooperative mode of planning and operating interconnected electric utility systems, available transmission capacity within a system and transfer capability between systems is defined by complex system studies. These studies are based upon reliability criteria established by mutual agreement amongst power system engineers and performed by engineering study committees. This is a satisfactory arrangement since the engineers understand and trust each others' judgments.

The transfer limits defined in various regions of the country are based upon different security-reliability criteria. Within the current industry framework this is acceptable; the engineers involved have cooperated in establishing the acceptable criteria and understand their implications. Criteria used are based upon worst case evaluations assuming single contingencies in some regions and on double contingency evaluations in other areas. Limits are established based on normal and emergency circuit ratings and voltage limits at various points in the system.

As the number of non-utility generating entities increases and both wheeling and transmission access increase in the various scenarios, there is a greater and greater need for a simple definition of available transmission and transfer capability and the adoption of generally acceptable and understood criteria for use in establishing specific limitations. The entrance of competing entities envisioned by the scenarios means that there will need to be a simple scheme for defining the transmission capacity that may be used without the need for complex, cooperative engineering studies. The electric power system needs a quantity analogous to the "busy signal" in the telephone system.

This technical problem is intimately related to the reliability criteria adopted to ensure system security in system operations. Present practices have arisen since the 1965 Northeast blackout. "Credible contingencies" are analyzed and system operation limits are set based upon defensive operating tactics. These procedures establish transmission reserves required to cover potential emergencies.

Criteria for transmission system security analyses might be based upon probabilistic reliability indices as they may be in generation planning. This would lead to a more uniform level of system security and operating reliability. But the adoption of this type of approach would tend to result in a more complicated technique for establishing available capacity limits in the transmission systems than those presently used. This would defeat the purpose of establishing a simple definition and easily understood method for measuring this quantity.

This is an issue under all scenarios.

4.3 SPINNING RESERVES AND UNIT COMMITMENT

In the current industry structure the utilities have agreed upon operating guidelines which require each utility control area to maintain adequate spinning reserves. This is accomplished by using unit commitment practices which minimize total system operating costs for some time period.

The need for spinning reserves increases the generation production costs since more units must be operated than are required to meet peak loads. Many of the units running must be kept at lower output levels than those dictated by a pure economic dispatch.

The benefits of this type of operation are increased system security, better frequency control and regulation, and the ability to meet temporary generation shortages within local control areas rather than relying on the interconnected systems to provide support. These arrangements facilitate the functioning of the AGC systems.

As the non-utility generation levels increase in the various scenarios, it becomes increasingly important to ensure that spinning reserve levels are maintained at reasonable levels. Total reserve margins as well as the distribution of spinning reserves amongst individual units must be defined and controlled. This raises technical questions concerning the value of supplying spinning reserve to the system and how the spinning and ready (i.e., rapid start) reserves are to be measured.

The securing of generation supplies under contract terms offers the opportunity to establish a defined cost for providing this service. Selected sources for all generators could be required to supply or purchase this service as a condition for entry into the market.

Current unit commitment practices may be extended in the first three scenarios with the utility scheduling its own generators. If scheduling control of non-utility generation is required in the first three scenarios, it could be the subject of contract terms that might, for example, require utility payments for energy unsupplied because of unit commitment scheduled shutdown of non-utility generation (i.e. payments based on defined opportunity costs).

In Scenarios 4 and 5 a different approach is needed. IPPs and GENCOs with a group of units could be required as part of the contractual agreements to supply a given spinning reserve schedule. They could satisfy the requirements as they wished using their own commitment schedules. Metering and communications are required for monitoring to ensure compliance. Individual IPPs could be required to furnish or purchase spinning reserve capacity from the larger generating entities. The TRANSCO could act as a broker.

4.4 AGC SYSTEMS AND FREQUENCY CONTROL

AGC systems used to control system frequency and interchange are based on the current structure of utilities where control areas are clearly defined. Metering of tie lines into each area is an integral part of these systems and is easily accomplished.

Control actions of the interconnected utility areas are coordinated by mutual agreement so that each control area is responsible for supplying its own load demands. Each area must keep enough capacity online under AGC control so that it is not dependent on support from interconnected systems for longer than the period that emergency circuit ratings apply (i.e., 15 minutes).

The level of inadvertent interchange may be expected to increase under some of the scenarios unless proper contractual arrangements exist to require regulation to be supplied by non-utility sources as well as utility generation. Retail wheeling could increase inadvertent flows even more under Scenarios 2 and 5 without proper contract terms and control actions. Sources engaged in retail wheeling should be required to schedule generation to meet the requirements of the load cycle of the purchaser or to purchase load following generation from the local utility if they lack the ability to follow the customer's load cycle.

If inadvertent interchange levels increase to the point where they interfere with system operations and control and cause uncontrolled loop flows, the current system of repayment in kind should be replaced by one requiring direct payments in dollars. The rates should be high enough to encourage the generating entities to install better control practices and systems.

Technical problems are posed by the various scenarios related to AGC system functions. With larger levels of non-utility generating capacity connected to the transmission systems, remaining utility generators will be required to assume more of the regulating duty unless the supply contracts enable the control of this capacity by the utility AGC system.

If these units are to be treated as being outside of the existing AGC control areas, the number of metering points needed for the AGC system increases. With unrestricted access to the transmission system the very definition of a control area becomes fuzzy. Under scenarios that allow wholesale wheeling only, the larger sized non-utility generators may be treated as scheduled interchange by the AGC systems.

Retail wheeling is allowed under some of the scenarios where both utility and non-utility generators serve specific retail customers located locally or outside of the local control area. With a few such arrangements, the AGC systems can treat these as scheduled interchange transactions. Contract terms that specified the responsibility for the mismatch between the generating source and the retail customer would be required. Theoretically, it would be possible to treat each retail wheeling arrangement as a separate interchange transaction by requiring the generator to match the retail customer's load at all times. This complicates the control of the generation, requires additional metering and communications, and may make scheduled interchange vary at the same rate as the retail customer's load changes. It may require that the parties to the retail wheeling arrangement purchase regulating supplies from the wheeling utility, or the utility in which the retail customer is located.

In the last scenarios, the whole basis of current tie-line control becomes undermined since it presumes well defined control areas in which sufficient generation is under AGC system control. Under these scenario conditions, the current AGC system concepts could be extended if contracts between generation entities and the TRANSCOs responsible for system operation contained requirements for control of units by the AGC system. It is possible that control areas may be defined electrically, matching sources and load areas.

Also in the last two scenarios the number of independent generating entities increases and the AGC problem becomes more important to resolve. The current voluntary cooperative arrangements would have to be replaced by contractual arrangements which provide for required amount of generation control to ensure both frequency and interchange control. Metering and communication systems would need to be expanded to allow the monitoring of these arrangements to make certain that the various parties did not cheat.

Under the conditions of the last two scenarios, it might be desirable to consider separating the current large eastern and western interconnections into smaller synchronous interconnections to facilitate the monitoring and control of required generation performance. This would, of course, require the investment in appropriately sized dc interconnections to permit interchanges to take place between these new, smaller sized interconnected systems. The advantages would be larger, transient frequency excursions, permitting the easier detection of insufficient regulating capacity and the direct control of interchange between the interconnections over the dc ties. It would also reduce the extent of the coordination required by confining requirements to smaller interconnections.

The disadvantages of this proposal are mainly with regard to the limitations it might impose on economy interchange transactions. With oil prices high relative to coal fuels, there has been a general increase in the economic interchange from the midwest to the eastern areas of the country. Opening the ac ties and replacing them with back-to-back dc interconnections might severely limit this flow. The separation of the ac interconnections would require the opening of a large number of existing tie lines and would undoubtedly reduce the operating reliability of systems on the boundaries of the new reduced sized interconnections. Finally, reducing the size of the interconnections would severely limit the geographic extent of the markets for energy. For these reasons, this possibility seems only of theoretical interest.

4.5 SCHEDULING TRANSMISSION SYSTEM USE

Current energy control systems schedule and control power generation to maintain frequency, control scheduled interchange levels, and realize optimal economic operation. The transmission systems constrain this control. Transmission losses may affect the economic scheduling. Transmission system limitations and system security considerations are all recognized in the design of modern energy control systems, but as constraints to the primary control objectives.

Increased transmission access and wheeling and the entry of larger amounts of non-utility generation would change the basic nature of the scheduling problem. With large blocks of generation and retail load being supplied under wheeling contracts, it becomes necessary to be able to schedule and control the required transmission flows over the limited transmission capability for both long and short time periods. The longer periods (e.g., weeks up to years) are needed to establish non-conflicting wheeling contracts and the need for new transmission capability. The shorter transmission scheduling function would be desirable to maximize transmission system use, permitting optimal use of a limited resource within security constraints.

A simple example would be the supply of a load area over a single transmission path under conditions where generation is obtained under a number of different contracts, each with a different capacity and duration. The transmission system should ideally be scheduled to minimize the total cost supplying the load demand recognizing the limited transmission system capability. The problem as stated is similar to the classical, one dimensional "knapsack" problem in operations research. Under ideal conditions of well defined capacities and durations it is solvable by various methods.

Unfortunately, in actual electric power systems these ideal conditions do not exist. Transmission systems are complex and power flows obey physical laws and not contract terms. The transmission scheduling problem is therefore multi-dimensional with power flows extending over multiple transmission paths. Transmission capabilities vary with time due to different load and generation patterns and interchange levels. Finally, the real world problem is conditioned by a high degree of uncertainty caused by the inability to forecast loads and generation capability accurately and the unexpected outages of various parts of the system.

In Scenarios 4 and 5, the rate structures for wheeling affect any economically based transmission scheduling implementation. They will interact with the generation scheduling process as well, since optimal wheeling may be an alternative in establishing unit commitment and generation dispatch.

This is an important area which requires a solution under the conditions postulated in the last three scenarios. It is related to facilities planning, planning for both supply and wheeling contracts, operations planning, and real time system operations.

In order to implement any transmission scheduling procedures, the TRANSCOs (or utilities in Scenarios 1 through 3) must have control of sufficient generation to control transmission flows. With existing technology, generation shifting (i.e. control) is the key method for controlling transmission line flows.

4.6 BULK POWER SYSTEM PLANNING PROBLEMS

Planning problems related to the scenario conditions are caused by the increased uncertainties that arise with regard to the need for new bulk power system facilities and the increased uncertainties that non-utility generation will, in fact, materialize as announced.

The current industry structure vests the responsibilities for forecasting and planning in the utilities with regulatory oversight and de facto participation. Utility planning staffs forecast loads, evaluate the need for new facilities, and start the implementation process carried out by their utility organizations. They are faced with levels of uncertainty in load forecasting and in forecasting the future costs and service dates of planned additions.

As non-utility generators (QFs) have entered the market in the past, a new dimension has been added to the uncertainty. Generating capacity announced and planned by non-utility entities must be recognized in the utility planning process. The level of uncertainty associated with these new generating sources has been demonstrated to be very high. In both California and Texas the level of planned non-utility generation rose rapidly as high fuel price levels and PURPA avoided cost levels appeared to be on the rise. When fuel market prices declined, reducing expected payment levels for non-utility generated energy, many previously announced plants failed to materialize.

With existing, or even modified utility structures, this increases the difficulty in the centralized planning process. Under conditions of increased transmission access and separated utility functions, the uncertainty increases as separated functional organizations each make forecasts of load, local dispersed generation, and needs for transmission system facilities.

The assignment of part of the centralized planning responsibility to the market place, of course, has merit in that competitive market price levels would determine the entry of new supplies of generation as load increases required and prices responded. From a technical viewpoint and assuming currently available technologies, this may lead to periods of excess and deficient capabilities because of time lags inherent in planning and construction cycles for bulk power system facilities. In all of the scenarios, responsibility for system reliability and security is vested in the transmission utility entity in the more extreme cases, or in remaining utility institutions under the more moderate departures from the present industry. These organizations will need to plan system expansions to accommodate future non-utility resources and requirements for the transmission systems. The results of market directed fluctuations in the planned resources and transmission needs may cause excess facilities to be constructed in some periods and insufficient facilities in other periods.

In the planning of interconnected systems, cooperative planning studies are carried out by non-competitive utilities to determine intersystem transfer capacities and needs and to perform coordinated, regional planning studies. Data are exchanged freely concerning system forecasts and plans for new facilities. System operators exchange information to coordinate interconnected system operations that also aids the planning of interconnected systems. With a competitive environment the incentive for coöperative planning efforts decreases. The result might well be the inability to plan optimal, or near optimal systems with consequently higher costs to serve consumers requirements.

Solutions to the planning problem are mostly contractual and institutional. In the first 3 scenarios, QFs, IPPs and GENCOs could participate in the generation expansion by providing sufficient notice and responding to bids issued by the utility. In the last two scenarios, the TRANSCO has responsibility for coordination of planning and for planning the transmission system expansion. The TRANSCO should be made an essential party to any agreements for supply procurement early enough to assure that sufficient transmission capability is in place when needed.

4.7 PROBLEMS RELATED TO DISPATCHING

In addition to the problems associated with the scheduling of the transmission system use, other dispatching and control center problems will arise under the conditions of increased transmission access, wheeling, and non-utility generation.

Current economic dispatching methods control power generation levels to minimize the cost of real power production for the whole system. Security constraints and transmission losses may be included and transmission system incremental losses may affect the schedules. Spinning reserve requirements are used in developing unit commitment schedules. VAR schedules may be incorporated in the economic dispatching software and valued indirectly by their effect on transmission system losses.

With independent power producers forming a large part of the generation resources under some of the scenarios, the economic dispatching algorithms will need to place a value on the worth of VAR generation, spinning reserve service, regulating duty service and the rescheduling of generation for security and transmission scheduling. Contract terms with generators will determine the degree of dispatchability of the supplies and thus dictate the modeling of these resources in the dispatch and unit commitment software.

Metering, communication, and transaction accounting systems will need to be expanded in future control systems to handle the large increase in volume of transactions and controlled variables. Accounting for system losses and the allocation of responsibility for transmission system losses will be more complex. Data transmission systems between separated GENCOs, TRANSCOs and DISCOs will need to be developed or expanded and interorganizational billing systems will need to be developed. These will require the need for installation of larger, more powerful computer systems and data communications systems.

As the various scenarios depart from current conditions, more and more of the generation is supplied under contract terms. If the contracts are such that the majority of the power demands are supplied under non-dispatchable contract terms, the nature of the dispatching problem will evolve to one where contract scheduling is of primary importance and minimizing the system production cost is not. When this happens, the very nature of economic dispatch changes. System incremental operating costs (i.e., the marginal costs) will not have the same meaning they have currently. Currently system incremental cost represents the marginal production cost of generators free to be scheduled, unconstrained by loading limits or transmission capacity. If contract and transmission scheduling become paramount in the last three scenarios, marginal costs may represent the cost of substituting one transaction for another to increase production or transmission flows.

4.8 SOLUTION OF SYSTEM-WIDE PROBLEMS

The last major area of technical problems arising from the scenarios is that related to the analysis, solution and resolution of system-wide technical problems. These problems are those that involve the entire bulk power system such as emergency operation and the solution of system dynamic problems.

Integrated utility systems presently have the responsibility to investigate these problems, seek appropriate and economic solutions, and implement the solutions. Emergency operating procedures are developed by individual companies and groups of cooperating utilities to prevent cascading outages and to develop methods to restore service rapidly and efficiently after major emergencies. Transient stability problems and low frequency power oscillations are studied and remedies applied to prevent future occurrences. With independent organizations responsible for generation and transmission existing in a competitive environment, the voluntary cooperative efforts to solve these problems will need to be replaced.

The expansion of transmission access and the restructuring of the industry will not cause these system-wide technical problems to disappear. Past problems will reappear, perhaps in new locations, and new problems will develop as systems evolve.

The structures envisioned in the scenario descriptions will produce a more difficult environment in which to attack and implement solutions to system problems. The interconnected power systems are extremely complex and systems in one locality may interact with remote systems in unanticipated ways. The divided responsibilities which accompany scenarios with separated functional responsibilities will make it more difficult to attack system problems and assign the costs of implementing needed solutions.

The solution in the last two scenarios is to assign the responsibility for these system engineering problem solutions to the TRANSCO staff. All generating parties, DISCOs and retail customers engaged in retail wheeling contracts would be obligated to participate in solving these problems. Standard contract terms would be established to set the framework for implementation costs in solving the problems.

In the first two scenarios the utility retains this responsibility. QFs, IPPs, and GENCOs should be bound by contract terms to assist in solving and implementing system engineering difficulties as a requirement for entering the market.

Power Technologies, Inc.

TECHNICAL BACKGROUND AND CONSIDERATIONS IN PROPOSED INCREASED WHEELING, TRANSMISSION ACCESS AND NON-UTILITY GENERATION

R17-88

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TABLE OF CONTENTS

TABLE OF CONTENTS

PAGE

PREFACE

CHAPTER 1 - STRUCTURE OF ELECTRIC POWER SYSTEMS 1-1

1.1 A "TYPICAL SYSTEM" 1-1

1.2. HISTORICAL PERSPECTIVE 1-6

1.3 SERVICE STANDARDS 1-12

1.3.1 Voltage 1-13
1.3.2 Frequency 1-15
1.3.3 Service Reliability 1-15

1.4 GENERATION SYSTEMS 1-17

1.4.1 Hydroelectric Plants 1-19
1.4.2 Fossil-Fired and Nuclear Steam Generation 1-21
1.4.3 Combustion Turbines and Combined Cycle Plants 1-23

1.5 TRANSMISSION SYSTEMS 1-27

1.5.1 Overhead, Alternating Current Transmission 1-27
1.5.2 Substations 1-32
1.5.3 VAR Flows 1-33
1.5.4 High Voltage Direct Current Systems 1-36
1.5.5 Subtransmission Systems 1-38
1.5.6 Underground Power Transmission 1-38
1.5.7 "Typical" Transmission Systems 1-41

1.6 DISTRIBUTION SYSTEMS 1-43

1.6.1 System Configurations and Customer Classes 1-45

1.7 INTERCONNECTIONS 1-47

TABLE OF CONTENTS (continued)

PAGE

CHAPTER 2 - ECONOMIC OPERATION OF GENERATION CONTROL AND INTERCONNECTIONS 2-1

2.1 INTRODUCTION 2-1

2.2 SYSTEM OPERATIONS 2-2

2.2.1 Load Patterns 2-2
2.2.2 Unit Commitment 2-5
2.2.3 Economic Dispatch 2-7
2.2.4 Effects of the Transmission System on Economic Dispatching 2-10
2.2.5 Summary of System Operating Considerations 2-11

2.3 EFFECTS OF NON-UTILITY GENERATION ON SCHEDULING AND DISPATCH 2-12

2.4 POWER INTERCHANGE 2-13

2.4.1 Economy Interchanges 2-14
2.4.2 Wheeling 2-15
2.4.3 Inadvertent Interchange 2-17

2.5 POWER POOLING ARRANGEMENTS 2-17

2.6 POWER BROKERS 2-19

2.7 INTER-UTILITY TECHNICAL RELATIONS - NERC 2-21

CHAPTER 3 - GENERATION CONTROL FOR FREQUENCY, VOLTAGE AND SYSTEM SECURITY 3-1

3.1 INTRODUCTION 3-1

TABLE OF CONTENTS (continued)

PAGE

3.2 FREQUENCY CONTROL 3-2

3.2.1 Automatic Generation Control (AGC) 3-4
3.2.2 Transient Operating Phenomena 3-8

3.3 VOLTAGE CONTROL 3-10

3.4 SECURITY DISPATCH OF GENERATION 3-13

CHAPTER 4 - LIMITATIONS TO TRANSMISSION SYSTEMS 4-1

4.1 GENERAL COMMENTS 4-1

4.2 TRANSMISSION LINE LIMITATIONS 4-4

4.2.1 Reactance 4-5
4.2.2 Thermal 4-8
4.2.3 Voltage 4-9
4.2.4 Current 4-9

4.3 LIMITATIONS IN SUBSTATION EQUIPMENT 4-11

4.4 LIMITS RELATED TO SYSTEM PERFORMANCE AND OPERATION . 4-12

4.4.1 Power Flow Distribution - Effects of Circuit Outages 4-13
4.4.2 Loop Flows 4-16
4.4.3 Voltage-VAR Problems 4-20
4.4.4 Stability Problems 4-23
4.4.5 System Operating Security 4-25

CHAPTER 5 - IMPROVING OPERATIONS OF CURRENT SYSTEMS . . . 5-1

5.1 INTRODUCTION 5-1

TABLE OF CONTENTS (continued)

PAGE

5.2 IMPROVING EFFICIENCY - BENEFITS OF POWER POOLING AND BROKERS 5-2

5.3 POSSIBLE IMPROVEMENTS IN SYSTEM OPERATIONS AND CONTROL 5-5

5.3.1 System Operating Reliability Criteria 5-6
5.3.2 Possible Improvements in Systems Operations and Controls 5-7

CHAPTER 6 - PROSPECTS FOR INCREASING TRANSFER CAPABILITY . 6-1

6.1 INTRODUCTION 6-1

6.2 LOAD DIVISION LIMITATIONS 6-3

6.3 VOLTAGE LIMITATIONS 6-5

6.4 STABILITY RELATED LIMITATIONS 6-6

6.5 SYSTEM CONTROL LIMITATIONS 6-9

6.5.1 Security Related 6-9
6.5.2 Power Plant Response 6-12
6.5.3 Deliberate System Separation 6-14

6.6 TRANSMISSION COSTS 6-15

6.6.1 Line Costs 6-17
6.6.2 Circuit Breaker Costs 6-19
6.6.3 Transformer Costs 6-20
6.6.4 VAR Supply and Voltage Control Apparatus 6-21
6.6.5 Miscellaneous Costs 6-21

6.7 APPROXIMATE COSTS FOR NEW AC TRANSMISSION 6-22

TABLE OF CONTENTS (continued)

PAGE

CHAPTER 7 - WHEELING AND NON-UTILITY GENERATION 7-1

7.1 INTRODUCTION 7-1

7.2 WHEELING 7-4

7.2.1 Technical Considerations in Wheeling 7-7

7.3 NON-UTILITY GENERATION 7-17

7.3.1 Effects on Utility System Planning 7-18
7.3.2 Effects on System Operations 7-22
7.3.3 Disbursed Generation Sources 7-26

7.4 WHEELING OF NON-UTILITY GENERATION 7-28

7.5 A CAVEAT 7-33

CHAPTER 8 - SUMMARY 8-1

8.1 GENERAL BACKGROUND 8-1

8.2 ASPECTS OF SYSTEM CONTROL 8-6

8.3 TRANSMISSION LIMITATION AND TECHNICAL REMEDIES 8-11

8.4 WHEELING AND NON-UTILITY GENERATION 8-15

REFERENCES

PREFACE

PREFACE

This report is one of two submitted to the Office of Technology Assessment of the U.S. Congress (OTA) by Power Technologies, Inc. (PTI) as part of the effort of OTA to provide information to the Congress in the potential restructuring of the electric utility industry.

This report deals with the technological background of the industry in the U.S. The companion report, "Technological Considerations in Proposed Scenarios for Increasing Competition in the Electric Utility Industry," discusses the general technical aspects of the electric utility industry and those technical issues specifically related to increased transmission access, wheeling, and non-utility generation. A number of unresolved technological issues are set forth in this report.

The authors wish to express their appreciation to the various engineers in the industry who have been kind enough to supply data for these reports and who have reviewed the drafts of the texts. Specifically, we wish to thank the American Electric Power Service Corporation, the staff of the North American Reliability Council (NERC), various members of the NERC Operating Committee and the Electric Power Research Institute (EPRI.)

CHAPTER I

CHAPTER 1

STRUCTURE OF ELECTRIC POWER SYSTEMS

1.1 A "TYPICAL SYSTEM"

Electric Power systems in the U.S. are quite diverse in both size and structural components. A vertically integrated electric power system includes three basic subsystems:

1. generation,
2. transmission,
3. distribution,

as well as the utility's loads. A utility system may contain all or only one or two of these subsystems.

The power generation systems are the devices and apparatus used to convert one form of primary energy into electrical energy. Conventional generation includes steam powered plants that use coal, lignite, gas, oil or a nuclear fission reactor for the sources of energy. In addition there are hydroelectric power plants that convert the energy in falling water to electrical energy and plants that use combustion turbines or internal combustion engines to drive electric generators. Unconventional types of generation are based on the conversion of solar energy to electrical energy, the generation of steam from waste materials and the use of fuel cells in an electrochemical cycle that generates electric power. These systems generate alternating current (ac) electric power that varies at a frequency of 60 cycles per second (i.e., 60 Hz.)

Generation reserves (or capacity margins) are the difference between the total installed capacity and the annual peak load and are necessary for maintenance of the generating units and to meet unanticipated events such as higher than expected loads or the sudden forced outage of one or more of the generating units.

Figure 1.1 shows a simplified electrical diagram of the power system. The generators used will produce power at voltages in the order of 12,000 to 30,000 volts (or 12 to 30 kV where "kV" denotes 1000 volts) which is too low to transmit efficiently for any distance. Therefore, the generator voltages are raised using power transformers to the transmission system voltage levels that range from 110 kV up to 765 kV. Transformers and associated switching devices (circuit breakers and switches) are contained in substations which also contain various metering, control, protective system devices and data communication equipment. The distinction between these subsystems varies from system to system and with time in the same utility. What started as transmission may be relegated to subtransmission as the load has grown and higher voltage circuits added. Voltage ranges in the three subsystems are shown in Table 1.1.

TABLE 1.1

Voltage Ranges Found in Various Subsystems

Subsystem	Voltage Range
Transmission	110 to 765 kV
Subtransmission	23 to 138 kV
Distribution	
Primary	2.4 to 34.5 kV
Secondary	600 volts and below

Transmission systems transmit power to the loads from generation sources and permit the integrated operation of the power system. They allow the sharing of generation reserves and the interchange of power and energy with interconnected systems. Subtransmission systems deliver the power from the transmission system to distribution substations for ultimate delivery to the customers via the distribution system. The demarcation between subtransmission systems and transmission systems is not consistent in the utility industry.

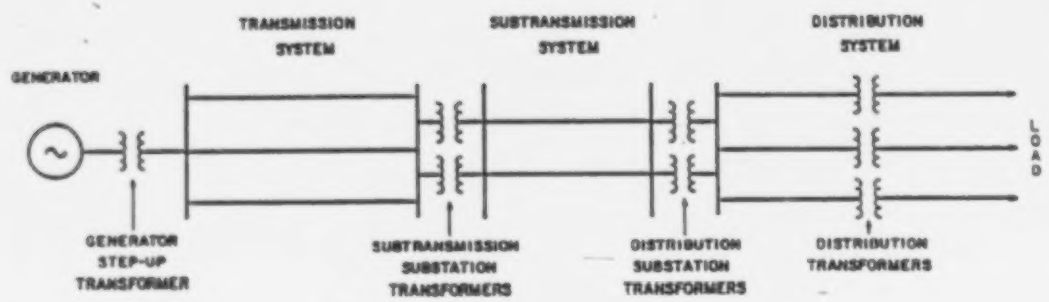

TRANSMISSION SYSTEM
SUBTRANSMISSION SYSTEM
DISTRIBUTION SYSTEM
GENERATOR
LOAD
GENERATOR STEP-UP TRANSFORMER
SUBTRANSMISSION SUBSTATION TRANSFORMERS
DISTRIBUTION SUBSTATION TRANSFORMERS
DISTRIBUTION TRANSFORMERS

Figure 1.1 - Simplified Power System

Subtransmission system voltage levels range from 23 kV to 138 kV and overlap the transmission voltages. A 115 kV line in a larger system will serve as subtransmission while in a small system, a 69 kV line may be a major transmission line. Only large customers such as major industrial plants are served directly from the transmission or subtransmission system.

Power is distributed to the ultimate, retail consumers over the distribution system. Voltage levels of the consumers' devices generally range from 600 volts for larger motors down to the familiar 110 to 120 volts used for lighting and household appliances. Transformers change the voltage levels several times. The distribution system itself uses voltage levels in the range of 2400 up to 34,500 volts and includes all voltage levels below the range used in subtransmission. These voltages have to be transformed again prior to connection to the customers' devices. In residential distribution systems these transformers may be in substations for the larger loads or in smaller pole-top or pad-mounted transformers found in residential areas.

The daily system load patterns found on U.S. utility systems generally have the appearance of the pattern shown on Figure 1.2. This is a simplified presentation which shows the "integrated load" for periods of two hours. That is, the power demand in megawatts (MW) in each period of two hours is shown as one half of the total energy (MWh) demanded for the two hour period. A strip chart of the load pattern (that is, a chart with finer time divisions showing the system MW load versus time) would be quite "noisy" (i.e., it would contain a large number of small variations at random, high frequencies) with numerous small peaks and valleys. The representation shown is typical and is adequate for examining phenomena that take place over a long period of time.

The system load is changing continually and in order to have a constant frequency, the generation level must also change continuously in order to keep the two in balance at all times. When generation exceeds the load demand, the system generators accelerate and cause the frequency to rise. A shortage of generation, on the other hand, will cause the system frequency to drop. Users' equipment is designed for essentially a constant frequency so that the utility's automatic generation control (AGC) system must keep the generation and load in balance at all times. Essential functions that are also incorporated in the control of the generation system are the economic scheduling of the generation for minimum operating costs and the scheduling of the local generation to keep the interchange of power with interconnected systems on the schedule that has been established. Chapter 2 reviews these aspects of electric utility operation.

The characteristics of power systems are quite diverse in the U.S., because of diverse historical development patterns, available energy sources and the nature of the load. Systems in larger metropolitan areas may have extensive underground subtransmission and distribution systems and very little local generation. In industrialized portions of the country the patterns may be closer to those that are frequently labeled as "typical". Power plants may be dispersed throughout the system's service territory and load and generation are interconnected with higher voltage lines. In still other utilities such as rural cooperatives and some municipal systems, only the distribution system may be present as the utility purchases all of its energy from an interconnected system. [1 - 3]

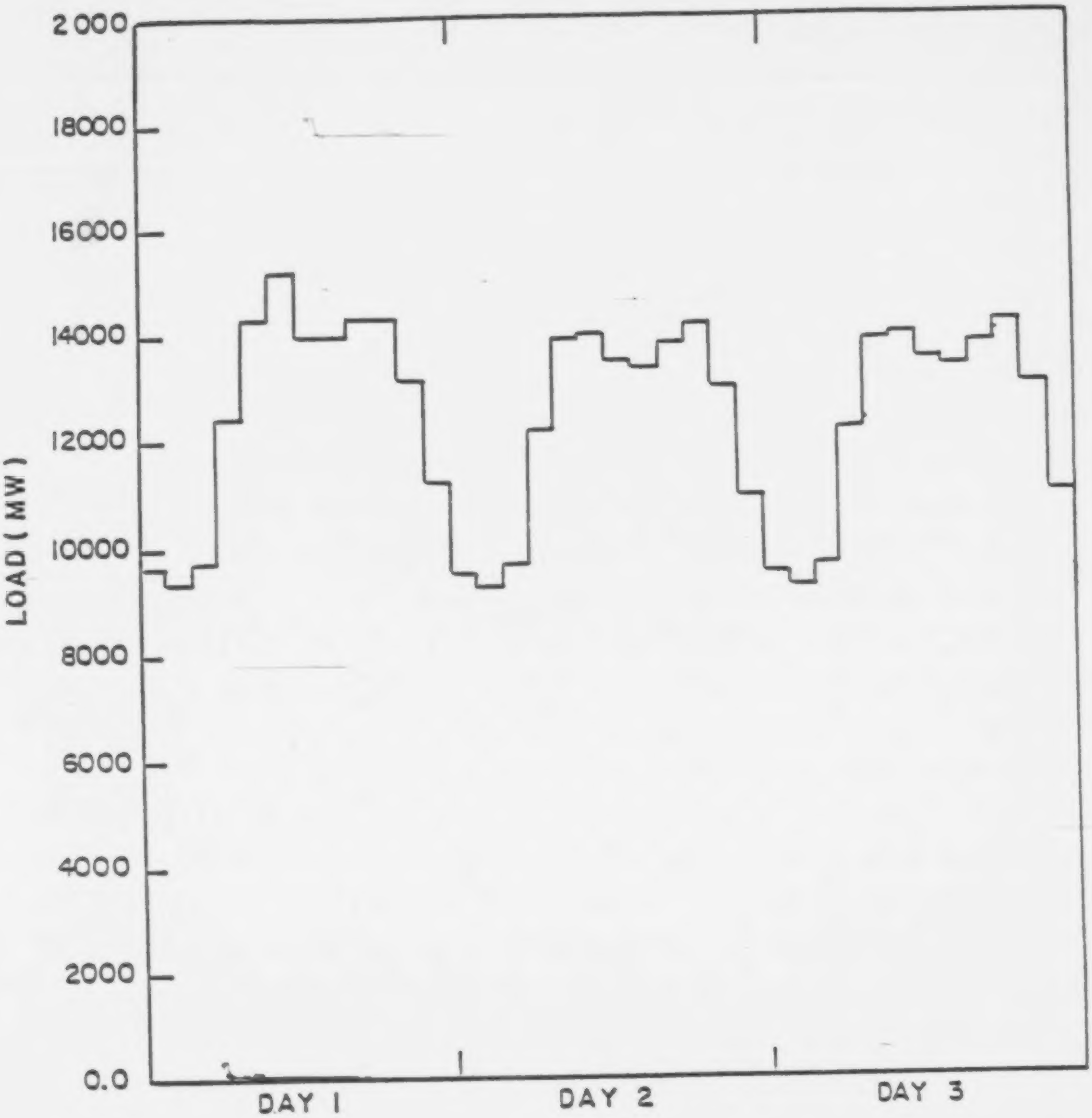


Figure 1.2 - Daily Load Curve

1.2. HISTORICAL PERSPECTIVE

The U.S. electric power system, began taking its current shape about 1905 with the early organization of "The Great Southern Grid." [4] This was the first time a group of independent power companies were brought together in a regional interconnection. Pioneered by the Southern Power Company, the interconnection spanned much of the Carolinas, Georgia, and Tennessee. It was the precursor of hundreds of similar interconnections formed by the 1930's, and set a pattern for a North American system that is largely planned and operated as four asynchronously connected networks, each operating at 60 Hz (60 cycles per second). These are comprised of over 200 independent investor-owned utilities, 1800 Municipal systems, several major federally-controlled systems, over 900 power cooperatives, and nearly 200 other governmental systems.

Systems at the turn of the century were largely municipal lighting companies, the most notable of which was served by Edison's Pearl Street Station in New York City, commissioned in 1882. Street railway companies also sold electricity as a side business. The introduction of alternating current (ac) systems, spurred by Tesla's invention of a practical ac motor, increased the range of central systems greatly since these new motors spurred many new applications of electric power. The first significant ac system carried hydroelectric power at 3.3 kV from Willamette Falls to Portland, Oregon, a distance of 13 miles.

The power generated at the Niagara Falls project was transmitted 22 miles to Buffalo via a 3 phase (or polyphase) ac system which incorporate 3 transmission wires plus a neutral to deliver the power. The success of the Niagara Falls project signalled the almost universal adoption of a 3 phase ac as a transmission medium in the U.S. As experience with ac was gained, the originally selected 25 Hz system gave way to today's 60 Hz standard, facilitating extensive synchronous interconnections.

The growth in U.S. electric systems was driven in large measure by innovations in utilization devices. Starting with the original impetus given by Edison's carbon filament light in 1879, a stream of inventions followed. The earliest were in primary devices such as generators, lamps, motors, transformers, etc. These, supplemented by a burgeoning control technology, led to a host of new power utilization devices, principally industrial drives and appliances.

At the same time technology improvements spurred by power demands also made possible larger turbines, generators, and steam supply systems, allowing utilities to achieve economies of scale and resulting in a continuous drop in the real price of electricity. These scale economies fostered the consolidation of the smaller local utilities into the larger systems of today. Larger blocks of generation and the expanded geographic base of power transactions led to higher and higher transmission system voltages. Voltages for regional U.S. transmission systems generally follow one of two sequences, 115 kV/230 kV/500 kV or 138 kV/ 345 kV/765 kV. The two highest voltages, 500 kV and 765 kV, were introduced nearly simultaneously in the 1960's. These different patterns of voltage levels do not preclude synchronous interconnections since ac transformers are used to connect ac circuits of different voltage levels.

The growth in generator sizes and transmission voltages seemed to be inexorable. But the 1000-1300 MW supercritical generation units of the 1960's and 1970's have apparently turned out to be a maximum, both technologically and economically.

Figure 1.3 illustrates the historic growth of single generator and single plant size as well as single transmission circuits. The figure shows the maximum capacities with the transmission capability of an overhead circuit measured in terms of "Surge Impedance Loading" (SIL). The surge impedance loading of an overhead transmission is a measure of a circuit's effective capacity.

The current technical limits to generating unit size are set principally by properties of available materials used to build generators and turbines. Steam turbine generator rotors for instance are limited by the strength of the forgings. Economic limitations result from the high capital cost and the effects of the unavailability of some large units plus the drop in the rate of load growth since the 1970's. The advantage of smaller generating units in an environment of uncertainty concerning price levels and load growth is apparent considering the constraints on capital resources faced by some utilities and the need of flexibility in planning and constructing new facilities.

The upward march in transmission voltages and generating units sizes halted at the same time, due to a combination of economic and environmental influences. Rights of way have become increasingly hard to obtain with costs rising dramatically. Line construction costs have escalated with the general inflation of utility construction costs. Environmental considerations concerning the effects of line construction, concerns over land use and potential health effects have led to the current situation where 765 kV class circuits are the maximum ac line voltage in use in the U.S. and Canada.

In some areas such as the interconnection of the Hydro Quebec system to the U.S. systems high voltage direct current (HVDC) has often demonstrated advantages by virtue of operating characteristics and declining installed costs. Direct current systems allow the direct control of power flows over the transmission circuits. This allows the four major networks in North America to be interconnected as well as permitting the "express" delivery of power and energy between remote areas.

Figure 1.4 shows the patterns of extra high voltage transmission circuits that exists in the U.S. and Canada today (1987) (Source: American Electric Power Service Corporation). "Extra high voltage", or EHV circuits are those operating at 345 kV to 765 kV. This map is not intended to be precise but shows the major transmission corridors where circuit voltages are 345 kV or higher. Underlying all of these EHV networks are extensive grids of lower voltage transmission and subtransmission networks. A map which included all of these low voltage lines would show the diversity of systems in the country, ranging from small consumer owned cooperative systems to the large utilities that serve major metropolitan centers. (Note that the North American Electric Reliability Council (NERC) in Princeton, New Jersey, has a similar map available that shows all circuits at or above 230 kV.)

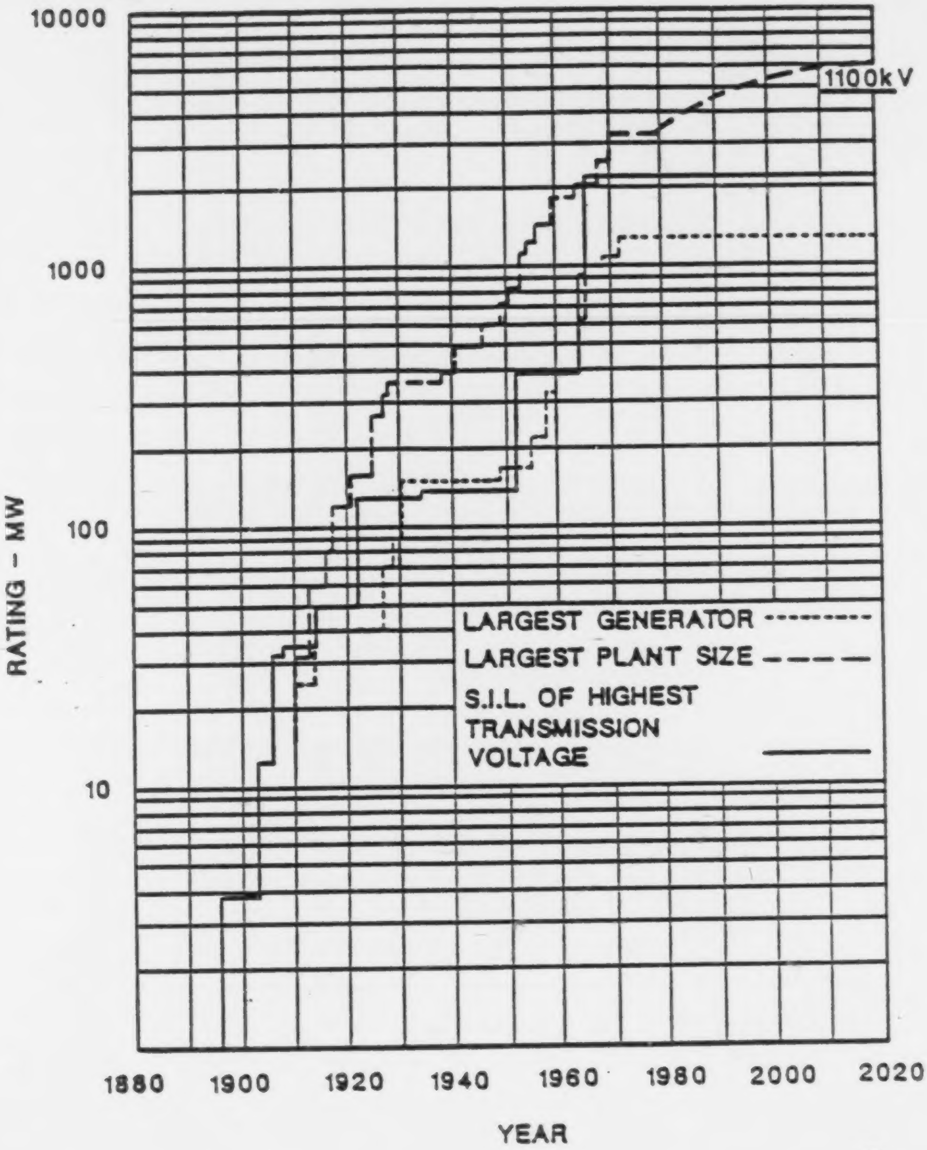


Figure 1.3 - Patterns of development of maximum generation and transmission capacity. Transmission circuit capability measured in terms of Surge Impedance Loading (SIL). SIL in MW equals a constant times the square of the line voltage in kV. The constant factor ranges between 0.0025 and 0.004, depending upon the number of conductors per phase.

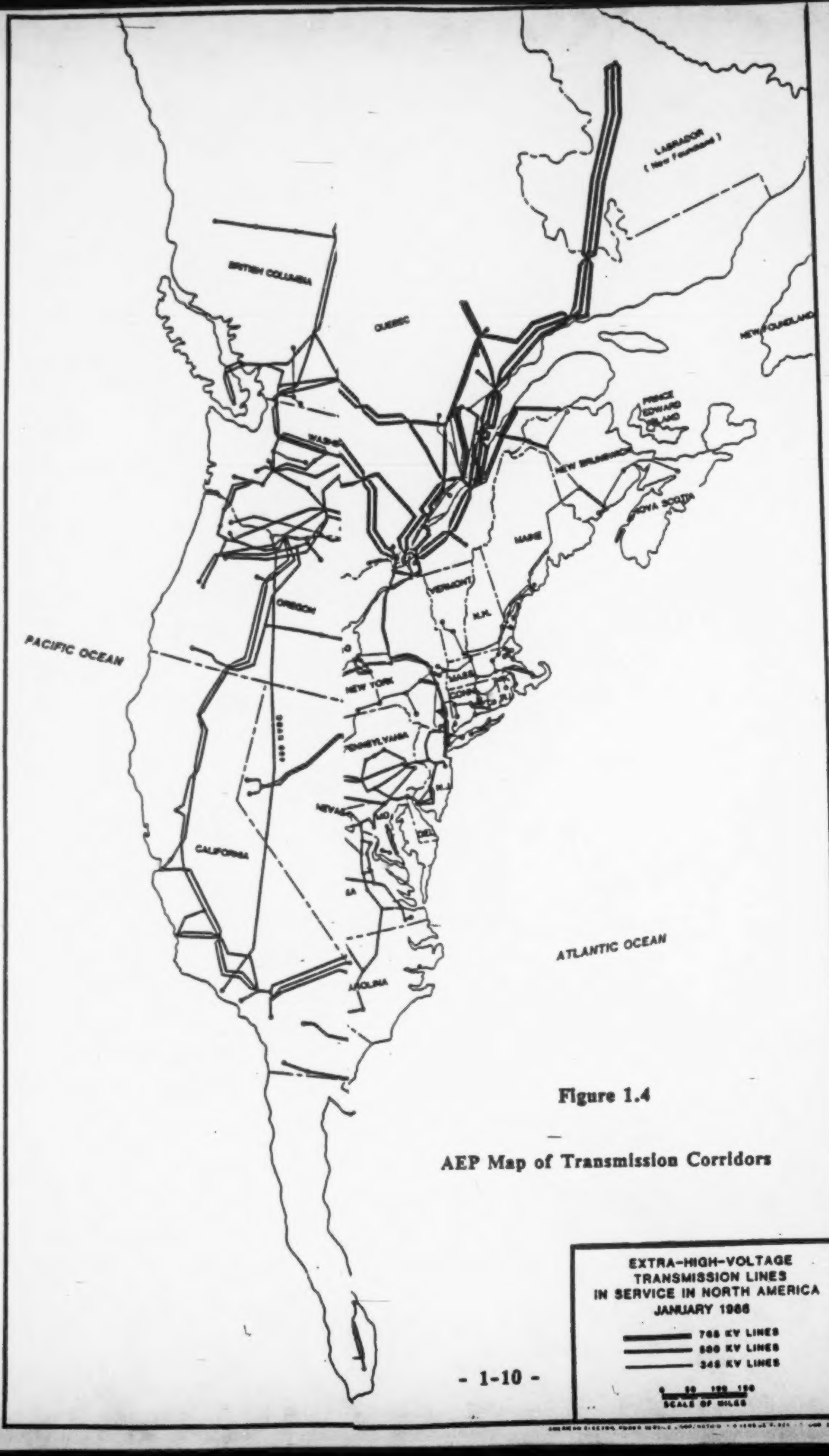

LABRADOR
(New Foundland)
BRITISH COLUMBIA
QUEBEC
NEW FOUNDLAND
PRINCE EDWARD ISLAND
NEW BRUNSWICK
NOVA SCOTIA
MAINE
VERMONT
N.H.
MASS
CONN
NEW YORK
PENNSYLVANIA
N.J.
MD
DEL
WASH
OREGON
NEVADA
CALIFORNIA
CAROLINA
GA
PACIFIC OCEAN
ATLANTIC OCEAN
EXTRA-HIGH-VOLTAGE
TRANSMISSION LINES
IN SERVICE IN NORTH AMERICA
JANUARY 1986
765 KV LINES
500 KV LINES
345 KV LINES
0 50 100 150
SCALE OF MILES

Figure 1.4

AEP Map of Transmission Corridors

The four major synchronously interconnected networks in North America are:

1. The portion of the U.S. and Canada East of the Rocky Mountains except for Quebec and portions of the State of Texas. Referred to frequently as the Eastern Interconnection.
2. The system in Quebec, the Hydro-Quebec System (HQ).
3. The system which serves a large part of the state of Texas. It is commonly referred to as the ERCOT system, the Electric Reliability Council of Texas.
4. The systems in Canada and the U.S. generally West of the Rocky Mountains. This is referred to as the WSCC system, standing for Western Systems Coordinating Council.

The reasons for this separation into four major interconnections are technical, economic and institutional. The Hydro-Quebec electric system contains a large block of remotely located hydroelectric plants. Figure 1.4 shows the long EHV circuits in this system that connect the remote hydro generation to the load areas. Because of these long transmission circuits it would be difficult and very expensive to interconnect the HQ system with the Eastern Interconnection with ac transmission lines. Therefore, transmission ties to HQ are all dc so the power flows may be controlled.

The WSCC system is separated from the Eastern systems by large areas of the U.S. and Canada from the Texas Panhandle north where the population and load densities are quite sparse. Any ac interconnections between these regions would have to be much larger than economically justifiable just to operate the systems successfully in synchronism.

The ERCOT system is interconnected to the Eastern Interconnection with relatively small dc circuits. The reasons for lack of synchronous interconnection are technical, historical and institutional. A synchronous interconnection between ERCOT, WSCC and the Eastern Interconnection would tie all of the U.S. into one synchronous grid through the Texas systems. To be effective these ties and the transmission system within ERCOT would need to be much more extensive than is required to serve the systems in ERCOT. A synchronous tie between ERCOT and the Eastern Interconnection system is technically feasible, but the opinion of many engineers in some of the utilities in ERCOT is that the system operating and reliability characteristics are better than they would be if the ERCOT system operated in synchronism with the Eastern Interconnection. Institutional considerations, primarily concerned with regulatory jurisdiction, have also led to the present situation where ERCOT operates separately from the Eastern Interconnection.

This then is the interconnection situation as it exists. Transmission of power between the four major interconnections is limited by the capacity of whatever dc links are installed between them. With the exception of the ties between HQ and the Eastern Interconnection, these are relatively small compared to the size of the systems. Interconnections between the Eastern Interconnection and HQ are fairly substantial and have grown as the eastern utilities have made arrangements to import Canadian energy to displace more expensive oil-fired generating capacity.

1.3 SERVICE STANDARDS

The subject of service standards in the electric power system is an important topic when reviewing typical system characteristics and considering the possible effects and potential technical limitations to a restructuring of the industry. The growth of the U.S. electric power system is due in a large measure to the growth in the availability of low cost, efficient utilization devices. Motors, appliances, heating devices, lighting as well as a multitude of electronic devices are all based upon the maintenance of relatively constant voltage and a constant frequency. These standards are taken for granted, but without these service standards for the supply of electric power to the retail customer, the manufacturers of electric devices would have to install power conditioning equipment to make certain that the devices would function properly and the utilization devices would become more expensive.

Power quality is another aspect of service standards. Electric power cannot contain harmonics and voltage surges must be prevented from damaging customers' equipment.

Reliability of supply is not a standard in the same sense as voltage and frequency since there are no published requirements. Nevertheless it is an important attribute of the power systems and deserves discussion along with the more formal standards.

1.3.1 Voltage

Controlling the voltage magnitudes supplied to utility customers is as important as supplying the correct amount of load power (MW) at the proper frequency. Voltage magnitudes must be within rather narrow ranges to ensure that the customers' electrical equipment as well as the utility system equipment will function properly and not suffer damage. Excess voltage levels, for instance will shorten expected service levels of incandescent light bulbs and may burn out appliance motors. Voltage standards have been adopted for transmission and distribution voltage levels. Standards are published by the American National Standards Institute (ANSI) in their standards publication C84.1 - 1980 and C92.2 - 1981. [5]

For distribution and lower subtransmission voltages (34.5 kV and below), the ANSI standards specify one range for normal system conditions and a different, slightly expanded range for emergency conditions. These voltage limits may be expressed in percent of the nominal system voltage. Table 1.2 below gives the allowable voltage limits for nominal voltages of 120 volts to 34.5 kV.

These voltage limits are for sustained conditions. Momentary voltage variations lasting only a few seconds that result from switching operations, motor start-up, and so on are excluded from these standards. Note that the difference in allowable voltage range between the normal and emergency system conditions is not large. To provide room for responding to emergencies, power systems are usually designed and operated so that the voltage variations stay within a narrower range than the standards allow.

TABLE 1.2

ANSI Standard Voltage Limits through 34.5 kV

Voltage Class (Nominal Voltage)	Voltage Limits in Percent of Nominal			
	Normal Operating Conditions		Emergency Conditions	
	Minimum	Maximum	Minimum	Maximum
120 through 600 volts	95%	105%	91.7%	105.8%
Above 600 volts through 34,500 volts	97.5%	105%	95%	105.8%

Voltages higher than 34.5 kV are not normally supplied directly to customers' utilization equipment. Therefore, the ANSI standards only specify maximum voltages for these voltage classes. Where customers do receive service at these higher voltages it is assumed that they will supply whatever voltage control may be needed. Table 1.3 below gives the maximum allowable sustained voltages for nominal voltage levels above 34.5 kV. Maximum voltage is given in both kV and percent of nominal.

TABLE 1.3

ANSI Standard Voltage Limits above 34.5 kV

	Nominal Voltage (kV)	Maximum Voltage (kV)	Maximum Voltage % of Nominal
	46	48.3	105
High Voltage	69	72.5	105
	115	121	
	138	145	
	161	169	
	230	242	
Extra High Voltage	345	362	105
	500	550	110
	765	800	105
Ultra High Voltage	1100	1200	109

Transmission system equipment, such as power transformers, may be damaged by sustained high voltages. Low voltage limitations on the system are set by voltage control capabilities and the system's operating practices. It is not unusual to find sustained voltages as low as 92 to 95% of nominal at a few points in the transmission system.

1.3.2 Frequency

A constant frequency supply at 60 Hz is actually taken for granted in the design of utilization equipment. The general public relies on this constant frequency for timekeeping functions. In actual fact frequencies on electric power systems do deviate from 60 Hz, but rarely beyond 59.9 to 60.1 Hz. A small error in frequency causes the automatic generation control systems to function. Generation control systems are designed to hold frequency constant by adjusting system generation to meet the demand exactly. Frequency standards are not subject to formalized codes but are set by the practical limitations imposed by system operations and limitations in both generating equipment and customers' utilization equipment.

1.3.3 Service Reliability

Given the various kinds of events (e.g., equipment failures, lightning strokes, storms, etc.) that may cause service interruptions, there are at least three physical dimensions that may be used to measure service reliability:

a. the magnitude of the outage (MWs of load interrupted, MWh of load energy not served, number of customers interrupted, etc.).

b. the frequency of service interruptions (expected number of occurrences per year).

c. the expected average duration of the outages. [6 - 9]

These measures are in fact interrelated. In the past, electric system customers have exhibited a tolerance for frequent interruptions if they are of a short duration. When the average duration becomes too long, the perception of service quality declines.

In the future as commercial establishments (i.e., business offices, stores, etc.) become more dependent upon electronic systems, even short duration outages may become intolerable. The system itself (that is, the operators, managers and owners of the system) can only tolerate interruptions of a large magnitude if they occur very infrequently. One would expect that a utility executive would respond with "Never!" if asked how frequently the system could stand a widespread blackout or wished to experience the effects of a widespread outage due to storm damage.

The establishment of absolute standards of service reliability using these three measures is difficult given the subjective nature of the varied views of the importance and economic value of reliable service by the customers of the electric systems. There are no comprehensive published service reliability standards: only the de facto standards that have arisen over the years in the industry.

Efforts to place an economic value as determined by the retail consumers on the loss of service have not resulted in the establishment of universally acceptable, quantitative criteria. Engineering planners use various service reliability criteria measures to develop alternative plans which exhibit similar levels of expected reliability indices. Probably the best known is the "loss of load (or energy) probability" which is a measure of the cumulative duration of the expected, long term average capacity (or energy) shortage of the system as a whole. Indices such as the expected number of customer or customer-hours of interruptions per year may be used in evaluating distribution system design alternatives.

Engineers who develop and use these measures are making comparative analyses of expected service quality. The definition of "reliable" service is a subjective matter. What is acceptable to a residential consumer may not be to a large retail concern. In developing the plans for the electric systems to serve these two classes of retail customers the utility engineer may recognize this difference by designing highly redundant supply circuits to the large retail concern.

The service reliability levels must be acceptable. They have not been quantified and codified to date. Exactly what levels are tolerable and how they are to be measured is still not firmly established. The service reliability levels of today's systems in the U.S. and Canada do not appear to be unsatisfactory in general.

Whether these de facto standards that exist are too high or are minimum levels of service quality is unknown.

These service reliability levels are also quite important determinants of the usable transfer capability of the transmission systems, and thus play an important role in any discussion of the ability of these systems to wheel power to a greater extent than they already are doing.

1.4 GENERATION SYSTEMS

The mix of generation types and fuels sources varies in U.S. power systems from year to year as new capacity goes online and older units are mothballed or retired. Currently (1987) the nuclear and hydroelectric capabilities are each about one-eighth of the total U.S. capacity while the steam plus combustion turbine segment represents about three quarters of the total capability. Table 1.4 shows the estimated total U.S. installed capacity by type as of the end of 1986. [10 - 13]

The electric energy sales in 1986 were about 2,360 billion kWh. The generation totals by various fuels are shown for that year in Table 1.5.

The generation total in Table 1.4 does not equal the reported total sales because of a number of factors including the energy losses, the reporting of imports and exports of energy and the discrepancies that arise because of different reporting periods for generation and sales.

TABLE 1.4

U.S. Total Generation Capability as of December 31, 1986

TYPE	MW Installed	% of Total
Hydro	85,193	12.0
Fossil Steam	474,063	66.9
Nuclear	93,182	13.1
Combustion Turbine	51,649	7.3
Internal Combustion	45,007	0.7
Total Capacity	709,094 MW	100.0%

Source: Electrical World, Statistical Issue, April, 1987, page 52.

TABLE 1.5

Electric Energy Generation By Various Fuel Types for 1986

Fuel Type	Billions of kWh	% of Total Generation Shown
Hydro	290.8	11.7
Nuclear	414.0	16.6
Coal	1,385.8	55.7
Oil	136.6	5.5
Gas	248.5	10.0
Other	11.5	0.5
Total	2,487.2	100.0%

Source: U.S. DOE/EIA - 0035(87/06), Monthly Energy Report, June 1987.

1.4.1 Hydroelectric Plants

Hydroelectric power plants convert the energy stored in water at a higher elevation by releasing it through a hydraulic turbine to a lower elevation. The power available is proportional to the product of the flow rate times the net elevation that the water falls. Plants may be classified by the relative magnitude of the plant's "head" (i.e., approximately equal to the vertical distance that the water falls) and type of turbine or by the nature of the associated water storage system. The latter is more convenient for discussing the role of hydroelectric power in scheduling of the system operation.

In some watersheds there are very large reservoirs that can store the inflows of water for a season, a year or even longer. These, as well as plants with smaller reservoirs, are classified as storage hydro plants. They can usually be scheduled in a flexible manner so that the water is released in a pattern that is most advantageous for serving the electrical demand patterns. There are, however, many constraints in operating storage plants. In some cases water must be released on a fixed schedule to accommodate the requirements for irrigation or the spawning of fish.

"Run-of-river" plants are dependent on the flow in the river for the flow through the turbine and usually have little or no storage capacity. Plants of this type are frequently found on river systems where the elevation drop is modest. Other types of hydro plants have been constructed where the water is pumped into elevated reservoirs and then released later through hydraulic turbine generators. The merit of this type of plant, known as a "pumped storage" plant, is that water may be pumped during off peak load hours at a relatively low cost for the electrical energy required and then released generate power to displace relatively high cost energy during periods of peak loads on the system.

From an operational viewpoint hydroelectric plants have a number of desirable features. They may be started relatively rapidly and they respond to load change requirements rapidly when compared to large steam turbine generator units. Pumped storage plants may contribute to the spinning reserve capability of the system.

Spinning reserve is the difference between the total generating capacity that is being operated and the expected peak load and is required to meet unexpected load increases and sudden forced outages of generation. Plants that are in a pumping mode may be shut off rapidly to reduce the system load. Pumped storage plants that are in a state where water is in the storage reservoir may be started and brought up to load fairly fast.

The two basic types of operational scheduling (viz., long and short term scheduling) associated with the economic operation of storage hydroelectric plants are concerned with the optimum use of the water in the generation of electric energy. [14] . The long term scheduling of the resource is concerned with the prediction of the expected inflows into the reservoir system and the optimum scheduling of water use over a long time period (i.e., "drawdown" of the reservoir) so that power production needs are met without wasting water and the reservoirs will be at the proper levels to accept a new inflow when the cycle is to be repeated. Water inflows are estimated considering factors such as the depth of the snow and the weather statistics of the region. The result of the scheduling is a pattern of water usage over the next month, season and possibly year(s).

In a region such as the Pacific Northwest where the area is dependent upon a reliable source of hydro power, operating policies must be developed so that both the probability of wasting water by not scheduling enough generation and the risk of running out of water by using too much of it are balanced. Hydro system operators have developed models and schemes for scheduling the drawdown of the reservoirs in optimal fashions.

The other type of scheduling problem is the short term problem that is concerned with developing optimum power production schedules for a day, week or month so that the scheduled amount of water is used. In the short run, storage plants are scheduled in such a way that a set, total, amount of water is released for the period in such a fashion that the costs of alternative electric energy sources are minimized. This must be done observing all the various types of constraints that may exist on the plant's operation such as the requirement to release water for irrigation, for fish ladders, etc.

The scheduling of pumped storage plants is done on a similar basis with the intent of minimizing the overall total cost of production during a given short time period such as a day or week. In this case, however, the operators usually have complete control over the inflow of water into the storage reservoir.

1.4.2 Fossil-Fired and Nuclear Steam Generation

The vast majority of the electric energy in the U.S. is produced in steam plants where a steam turbine is used to extract energy from high temperature, high pressure steam that is produced in either a fossil-fired boiler or by a light water moderated nuclear reactor that serves the same function as the boiler in a fossil plant. These units range in size up to 1300 MW and are located in fairly large plants. The average size is approximately 600 MW. Temperatures and pressures are in the range of 1000 degrees F and 2400 pounds per square inch gauge for modern fossil-fired units.

The basic components of a fossil-fired plant are indicated in simplified form on Figure 1.5. The furnace and boiler serve the functions of fuel combustion and the conversion of the feedwater into high temperature, high pressure steam. Boilers are very efficient (82 to 90+%) and are of two basic design types, the drum boiler and the "once through" boiler. In the drum boiler, steam is separated from the heated water in a large drum located on top of the boiler. The drum stores both water and steam. In the once through type, steam is created in the tubes which line the boiler furnace walls and is fed directly into the turbine. In both types the boiler controls are designed to maintain steam temperature and pressure, provide the control of the fuel and combustion air as well as ensure the protection of the boiler in the case of failures and when the unit is required to drop load and be tripped from the line. The turbine extracts energy from the steam and drives the turbine generator that produces the electrical power.

Coal fired plants of recent vintage may have flue gas scrubbers installed on the furnace to remove the sulfur from the stack gases. All coal fired plants have some sort of system attached to the furnace exhaust to remove fly-ash from the stack gases. In a coal fired plant the coal must usually be pulverized before being blown into the furnace for combustion. The furnace auxiliaries and fuel handling equipment are simpler for a gas or oil fired unit.

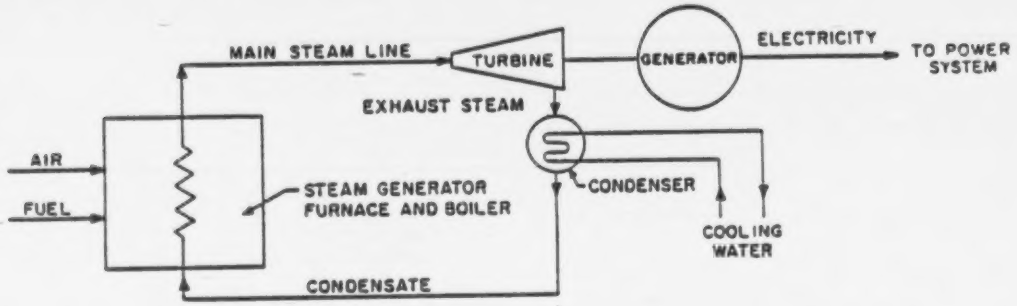


Figure 1.5 - Simplified Diagram of a Steam Power Plant

In a light water moderated, nuclear power plant the reactor uses the heat released in the nuclear fission process to produce steam to drive the turbine generator. There are two basic types of light water reactors in use in U.S. plants, the pressurized water reactor (PWR) and the boiling water reactor (BWR). In the PWR there are two isolated paths for the hot water in the reactor and the steam flowing in the turbine. Heat is transferred between the two isolated loops to generate the steam to expand in the turbine. The water which is in the reactor core and is exposed directly to the various fission products is contained in a separate path. In the BWR the water in the reactor core is transformed into steam within the core and allowed to expand through the turbine. The reactors are controlled by:

1. Using movable control rods made up of neutron absorbers.
2. Controlling the concentration of neutron absorbing material that is dissolved in the water in the core (PWR).
3. Changing the reactor recirculating water flow rate (BWR).

The turbine generators of steam plants are controlled by a sequence of systems. To alter the energy flowing into the turbine, steam admission valves are controlled. The turbine speed is controlled by the governing system that has a characteristic that causes the speed to drop when additional load is applied to the turbine. This "speed droop" is required in order to permit generating units to share load when operated in parallel. The governor characteristic is adjusted by the control that sets the required output from the unit. This is under the control of the automatic generation control (AGC) system that includes both the economic dispatch system that sets the optimum economic generation levels of the units and the supplementary control system ensures that the proper level of total generation is held within the area under control. Ultimately the changing of the output level of a steam generator requires that the rate of fuel entering the furnace, or the reactivity level of the nuclear reactor core, be adjusted so that the required steam may be generated. The fossil fired plant boiler may be controlled using various control schemes to control temperatures, pressures, and the fuel feed to the furnace.

In the nuclear reactor basic load level changes are accomplished by the manipulation of the control rods. Withdrawal of these rods from the core allows the fission process to increase, augmenting the production of steam. In the BWR the recirculation water flow rates may be controlled to permit load following. Nuclear reactor units in the U.S. are normally operated at ether fixed load levels or else the load levels are changed at a gradual rate to facilitate the management of the nuclear inventory of the core and avoid potentially damaging power transients. Larger fossil fired steam plants are normally allowed to change load levels at maximum rates which are approximately 1 to 3% of the machine's rating per minute in order to limit thermally induced stresses. Both types of steam plants require time to bring them online and up to load when they are first started, or are restarted after being off line long enough to cool. Nuclear reactors that have been tripped off line and had neutron poisons (boron) injected into the water in the core to stop the fission reaction will take over a day to bring back online if they are not restarted fairly soon after being tripped off.

1.4.3 Combustion Turbines and Combined Cycle Plants

In a combustion turbine plant the working fluid (usually air) is compressed and heat energy is added to the working fluid by the combustion of fuel within the working fluid. The resulting high temperature gases are then expanded in a turbine which drives the compressor and the generator. The exhaust of the combustion turbine may be discharged directly into the atmosphere (a simple cycle) or cooled by passing the exhaust gases through a heat exchanger where the available heat energy is used to create steam that is expanded in a steam turbine (a combined cycle).

Simple cycle combustion turbines are normally applied in utility systems for peaking duty and for emergency reserve capacity. Typically they have been units with relatively expensive fuel costs and low installed, capital costs, characteristics which make them suitable for applications where they will be expected to operate only a relatively few number of hours per month. Efficiencies are typically in the range of 25 to 30% for older units but are expected to be over 30% for advanced design units which will use higher operating temperatures. Unit capacities range up to over 100 MW for the advanced design combustion turbines with the average size of the installed simple cycle units being much smaller.

Combined cycle plants generally have much better efficiencies than simple cycle units, approaching or even exceeding the efficiencies levels of the large steam turbine units. Figure 1.6 shows a block diagram of a combined cycle plant with four combustion turbines and one steam turbine. The exhaust of each combustion turbine flows through a heat recovery steam generator (HRSG) that creates steam for use in a steam turbine. Plants may be designed so that a steam turbine boiler may be separately fired to increase the plant's capacity and to ensure operation of the steam turbine during outages of the combustion turbines. Combined cycles have been designed with one to as many as four combustion turbines.

The output level of the combustion turbine driven units is controlled primarily by controlling the fuel input into the unit. Some degree of control may be provided by control of the gas paths in the system. Fuels may be oil or gas. Combustion turbine power plants may be started and brought up to load rapidly.

A new type of combined cycle plant, the integrated gasification combined cycle (IGCC) plant has been demonstrated recently on the system of the Southern California Edison Company [15]. This plant, the Cool Water Plant, converts coal to medium BTU gas for use in a combined cycle plant. This type of plant has the advantage of using a low cost and abundant fuel in a plant cycle that offers the opportunity to achieve high plant efficiencies in relatively modest sized capacities. In planning for system growth an advantage claimed for this type of plant is that it may be constructed in modular stages starting with simple cycle units, progressing to a conventionally fueled combined cycle plant and ultimately to a coal consuming IGCC plant.

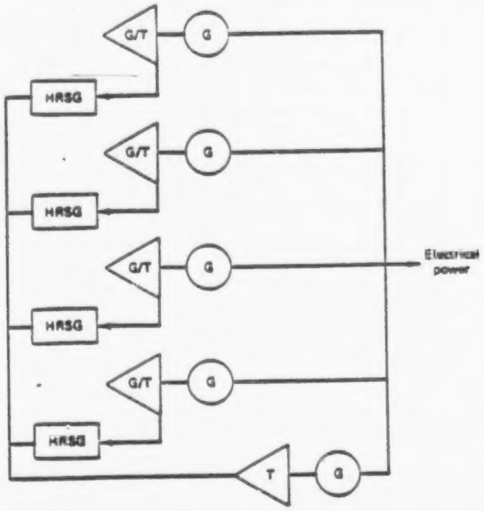


Figure 1.6 - A combined cycle plant with four combustion turbines and a steam turbine generator. "G/T" denotes a combustion, or gas turbine and "T" the steam turbine.

Although there has only been limited experience in operating this type of plant, one might hazard the opinion that commercial plants of this type will probably be operated as base load units because of the complex interactions of the chemical plants used for coal gasification and scrubbing of the fuel gas with the power generation cycle. Theoretically there is no reason why this type of plant could not be used for supplying varying loads on the electrical system, but because of the complexity of the plant and the time required for start-up it is doubtful that an IGCC plant is suitable for two shift operation (i.e., daily economy shutdowns) much less for peaking duty.

Cogeneration power plants which produce both industrial process steam and electric power are expected to supply a significant portion of the future demand growth for electric energy [16]. With the enactment of the Public Utility Regulatory Policies

Act of 1978 (PURPA), industrial concerns were offered an added economic incentive to establish new cogeneration plants and the opportunity to sell excess generation to utilities at "avoided cost". In industries requiring steam for their processes, the installation of new cogeneration facilities:

1. Provides a supply of process steam.
2. Offers the opportunity for self-generation of the electrical energy requirements of the plant.
3. Offers the opportunity to sell the excess power generated to the local utility and recoup the investment faster.

Since 1978 many concerns have constructed new cogeneration plants based on the use of combustion turbines in combined cycle configurations that produce both process steam and electrical energy [17]. The particular cycle design used in a given plant is dictated by the need for a reliable source of process steam as well as the economic considerations involved in selling the excess electrical energy and capacity to the local utility. From a technical point of view, assuming that all the possible problems regarding the electrical interconnections, etc., have been solved, a major potential utility operating problem associated with these plants is that the level of the cogeneration plant electrical output is dictated by the need for process steam. The resulting power generated must be absorbed somewhere.

The earliest types of cogeneration plants used automatic extraction steam turbines where the level of electrical output of the unit may be controlled over a wide range while still satisfying the need for a given level of process steam generation. The level of steam generated by a cogeneration plant using a conventional combustion turbine is dictated by the energy in the exhaust gases from the combustion turbine and there is usually only a small range of control of the electrical generation level for a given rate of steam production. This may complicate the coordinated operation of a utility's power generation facilities with cogenerators if the utility area has too many cogeneration plants of this type of design.

1.5 TRANSMISSION SYSTEMS

Power transmission circuits are generally in the 110 kV class or above. Most of the transmission in the U.S. consists of three phase, ac overhead construction with some high voltage dc used for special situations. There are segments of underground cable used for transmission, but these are relatively rare when compared to the installations of overhead transmission lines because the cost of underground transmission is usually much more than for overhead transmission.

At the end of 1986 there were approximately 612,000 circuit-miles of overhead lines in the U.S. with voltage levels at, or above 22 kV [10]. Of these, about 315,000 circuit-miles, a little over 50%, were at transmission voltage levels, 110 kV and above. The EHV transmission system shown on Figure 1.4 represents about 12% of the total circuit miles of the transmission system with most of the circuit-miles of lines at voltage levels of 110 to 230 kV.

1.5.1 Overhead, Alternating Current Transmission

Figure 1.7 illustrates the construction of two types of towers used in the building of 500 kV circuits. The towers support the phase conductors using insulators to keep the energized conductors away from the tower structure and from each other. Ground, or shield wires are supported at the top of the structure to protect the phase conductors from direct lightning strokes. The spacings and dimensions of the tower structure and the width of right-of-way required are determined by the voltage class of the circuit considering the need for air insulation to prevent the energized circuits from flashing over (i.e., arcing between the energized conductor and tower), the allowable electromagnetic field strengths on the ground and the prevention of high levels of radio interference patterns and audible noise.

The reason for the high voltage is the need for high capacity, low loss lines. The power transmitted is proportional to the product of the circuit voltage and the phase current. Power transmitted may be increased by raising the current while using larger conductor diameters to hold down the losses. In fact, at the extra high voltage (EHV) levels of 345 kV and above, it is usual to find circuits constructed with 2, 3 or 4 conductor bundles used in each phase. This method of increasing circuit capacity by raising currents has its limitations, both technical and economic. It is more practical and economical to increase transmission voltage levels as the need for higher capacity circuits has grown. For all practical purposes the maximum loading capability of a given voltage class of circuit is proportional to the square of the nominal voltage.

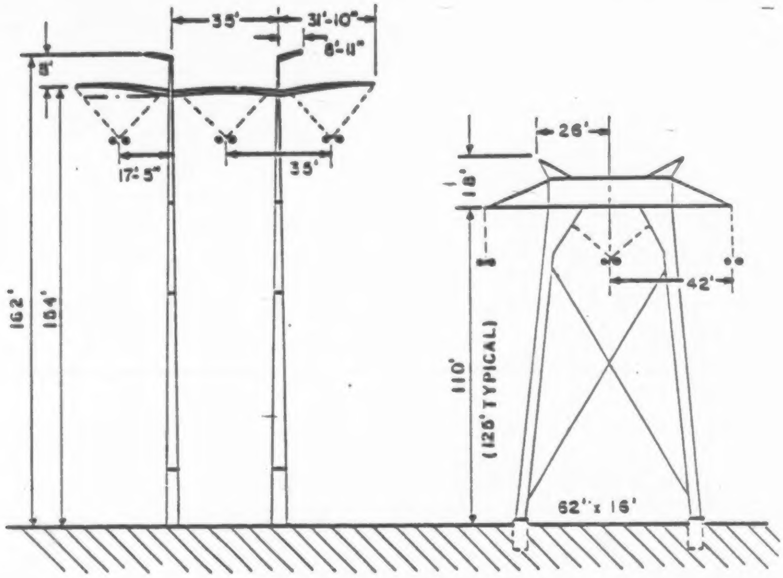


Figure 1.7 - Typical 500 kV Pole-Type Structures used on Present Systems

The concept of Surge Impedance Loading (SIL) is useful in discussing the limitations of overhead ac transmission circuits. The sidebar on SIL loading limitations points out that these are determined for idealized, straight away, express transmission.

SURGE IMPEDANCE LOADING RATINGS FOR OVERHEAD TRANSMISSION LINES

The concept of Surge Impedance Loading (SIL) ratings for three phase, overhead power transmission lines is a convenient and shorthand way of recognizing the effects of voltage class, distance and loading as parameters of an overhead circuit [18, 19].

First, the "surge impedance" of a circuit is related to its physical parameters: conductor diameter, spacing between phases, number of conductors used in each phase "bundle", and height above the ground plane of the conductors. It is also the value of the resistance that may be used to terminate the circuit so that no reflections take place of transients such as caused by lightning or circuit switching. In the steady state on an ac circuit, terminating the line with a load demand where the load power is equal to the square of the voltage divided by the surge impedance, results in a situation where no additional voltage support need be supplied at the load end of the circuit. This loading is sometimes referred to as the "natural loading" of the line.

When studies are made by electric power engineers of the maximum feasible circuit loadings for different voltage levels and straight-away transmission distances, line limitations are surprisingly independent of the circuit voltage rating when the loadings are expressed in normalized power units based on the SIL for that voltage class of circuit. (The maximum feasible loading levels in MW's are normalized by dividing the MW value by the SIL of that voltage). The maximum feasible loadings are determined by limitations imposed by:

1. Thermal characteristics of the phase conductors.
2. Voltage limitations of the circuit terminals and the related requirements for VARs.
3. Various types of system stability problems that may arise for long distance transmission.

Because of practical constraints on the physical characteristic parameters of overhead, high voltage line construction (i.e., spacings required for safety, insulating strength, etc.), the surge impedance values of overhead, three phase ac transmission circuits are almost independent of voltage level and are, in fact, mostly dependent upon the number of conductors used per phase. Lower transmission voltage level circuits, below the threshold of extra high voltage (EHV) lines are usually constructed with a single conductor per phase with the resulting surge impedance varying between 366 and 400 ohms. At and above 345 kV, two, three and four conductor bundles are used in order to reduce the impedance of extra high voltage circuits and increase the current carrying capacity of the line.

The table below shows typical surge impedance and SIL levels as a function of the nominal voltage class of the transmission line.

OVERHEAD LINE SURGE IMPEDANCE LOADING DATA FOR TYPICAL CONSTRUCTION PRACTICES

Nominal Voltage (kV)	No. of Conductors per Phase	Surge Impedance (OHMS)	SIL (MW)
115	1	400	33
138	1	400	48
161	1	400	65
230	1	400	132
345*	2	283	420
500*	3	248	1010
765*	4	258	2270

* Regarded as EHV levels.

Practical economic loading limits for overhead transmission circuits are based on both the technical limitations discussed and economic evaluations of required voltage support, additional switching stations, etc. Typical loading limits are independent of voltage level when expressed in terms of SIL ratings. They are dependent upon the transmission distance. The table below indicates these limits.

PRACTICAL ECONOMIC LOADING LIMITS FOR STRAIGHT-AWAY TRANSMISSION

Distance (Mi.)	Loading Limitations (Normalized in SIL Terms)	Limitation Cause
50 or less	3 x SIL	Thermal
100	2 x SIL	Voltage-VARs
200	1.45 x SIL	Voltage-VARs
More than 200	approximately 1 x SIL	Stability

These data provide guidelines for system planning engineers in selecting transmission voltages.. Circuit capacity requirements are the primary determinant of the required transmission voltage level. Specific circuit requirements and limitations must be investigated and determined in terms of the actual system and its operating and reliability-security practices.

These guidelines are a useful concept in transmission planning. Suppose we wish to consider alternative voltages for the "reliable" transmission of 1000 MW out of a power plant for 100 miles. This distance is convenient since the maximum loading is twice the SIL. Reliability practices in this example are taken to mean that the power must be transmitted even when a single circuit is lost. Suppose we use the data in the first and second tables to determine how many circuits of each voltage class are required.

kV Class (MW)	2 x SIL (MW)	Number of Circuits Needed for 1000 MW
115	66	17
138	96	12
161	130	9
230	264	5
345	840	3
500	2020	2
765	4540	2

Under normal circumstances a system designer would not wish to use a transmission voltage level less than 230 kV and would probably suggest that an EHV level be used.

Express transmission is seldom the case in actual systems as circuits are used to deliver power to intermediate loads, interconnect adjacent systems to facilitate the sharing of economy energy and system capacity reserves and to bolster up the system in the case of emergencies. Even so, the SIL concepts provide useful guides in planning transmission systems.

1.5.2 Substations

Power transmission substations are an integral part of the transmission network. These stations serve four basic functions:

1. They switch elements in and out of the system using high voltage circuit breakers that can interrupt load and fault currents and various disconnect switches that are not intended to interrupt high current levels. Protective relaying systems are connected to the circuit breakers and are used to sense abnormal circuit conditions and initiate the circuit openings.
2. They contain the various types of transformers that are used to step up or step down the voltages in the system.
3. They contain various devices used to regulate the system voltages. These include tap changers on the transformers and various types of VAR compensating devices.
4. They contain metering and communication devices and systems to collect and transmit data to control centers and to provide information to local protective relaying systems.

Different types of stations will have different names according to the intended function of the station. Thus there are switching stations, step-up or step-down stations and distribution stations.

The configuration of any station may be simple or complex with the difference being due primarily to the level of redundancy required in the switching arrangement. The level of redundancy in the switching scheme may be due to circuit configuration requirements and station reliability considerations. The electrical connector used to interconnect the various devices within the station itself is known as the busbar. Where space is not a limiting constraint on the station layout, air is used as the primary insulating medium. If space is a limitation (which is frequently the case in urban areas), gas insulated substations may be constructed.

Substations that contain measuring and communication systems provide information to the system operations center which needs to have up to the minute data on the system's power and VAR flows, circuit configuration (i.e., which circuits are closed and which are opened), and the voltage levels at various key points in the network. These data are used in the real time scheduling of the system.

1.5.3 VAR Flows

Reactive volt amperes, or VARs, are generated, absorbed and flow in ac power circuits. Real power that accomplishes work in the physics sense is measured in terms of MW and is the power delivered to the load to be transformed into heat, light or physical motion. The ac circuits used to transmit this power all support electromagnetic fields that store energy temporarily and that are required to accomplish the transmission of power and the transformation of the electrical power into some other form. For example, overhead transmission lines are surrounded by magnetic fields which store energy. They are in proximity to ground, an imperfect conductor, so that electric fields exist between the phase conductors and ground as well as between the conductors. These electric fields store energy as well. The maximum rate of change of the stored energy determines the VARs stored in these electric and magnetic fields.

VARS - A NON-MATHEMATICAL EXPLANATION

Perhaps one of the most difficult chores that can face a power system engineer is that of explaining the concept of "VARs" to the non-technical person.

An analogy may help to understand this phenomena. Suppose you were to use a wheelbarrow to move a load of bricks along a level road. To do so, you must first raise the handles of the wheelbarrow. When you do you are storing potential energy in the system. (It is easily discharged by dropping the handles.) Next you apply a force to the handles in a horizontal direction to move the load. You are doing work in the physics sense by applying this force to a mass to move it. Storing potential energy in the system by raising the handles was not your intent; but it was necessary in order to do the useful work. The height of the wheelbarrow handles is analogous to the power system voltage. As you move the wheelbarrow up and down hills the height changes just as voltages change in power systems when power flows through the circuits.

Such is also the case with VARs. It would be nice to be able to transmit power over an ac system without being concerned with VARs. But they are necessary because the circuit elements all involve some form of energy storage. The term VARs stands for Volt Amperes Reactive and is a short hand way of describing the rate of energy storage in an electric circuit that is subject to sinusoidal varying current flows. (Current flows are measured in Amperes and electric potentials in volts.) In a dc electric circuit where the voltages and currents are constant after any initial transients that take place have settled down, there is no change in energy storage in the circuit. Therefore, in a dc circuit the VARs have no usual meaning.

Most electric power circuits are alternating current (ac) circuits where the currents and voltages oscillate sinusoidally at a constant frequency of 60 cycles per second (or Hz.) Therefore in an ac circuit energy is being stored in and discharged from circuit elements every cycle. Conductors store energy in the magnetic fields which surround the conductor and, energy is also stored in the electric fields between the conductors and between the conductors and ground.

Because the ac current is not constant but is changing continuously the rate of energy storage is also changing. VARs are defined as the measure of the maximum rate of energy storage in the fields associated with the circuit elements.

An overhead transmission line, for example, stores energy in the magnetic fields that surround the conductors and in the electric fields that exist between the conductors and the ground. A power transformer or motor stores energy in the strong magnetic fields that are an integral part of these devices. When power is transmitted over the line there will be a flow of VARs as well. The VAR flow is necessary to support the stored energy and occurs because the energy storage in the electric and magnetic fields is changing each cycle. When the power flow is heavy, the stored energy levels are high and the power system at the ends of the circuit may need to supply additional sources of VARs.

The flow of VARs along the circuit causes voltage magnitudes to change. The VAR flows interact with the natural characteristics of the circuit that impedes the current flow to cause these voltage changes. Under light loading conditions VAR flows may cause voltage rises. Under heavy loading conditions they will cause voltage decreases. External VAR supplies and voltage control devices such as transformers with controllable turns ratios (i.e., "tap changing" transformers) may be needed to keep the voltage levels within reasonable tolerances (e.g., ± 5% of the nominal voltage.)

The current required to support the constantly charging and discharging energy storage must flow along the same circuit paths as the real power component of current. This flow of VARs has two major effects on the transmission circuits and system. It uses up a portion of the physical capacity of the circuit causing real power losses and heating of the circuit elements. The second phenomena that results from the VAR flow is the effect on the voltage magnitudes in the circuit. This later effect is complex and depends upon the exact circuit conditions. For example, during very light loading conditions on a long EHV line or on a high voltage underground cable, the flow of VARs required to store energy in the electric fields surrounding the active conductors will cause the voltage to rise along the circuit in the direction of the real power flow. For very long circuits this voltage rise may cause the receiving end of the circuit to exhibit voltages higher than those allowed by voltage standards, endangering the circuits and apparatus in the substation. On the other hand, when the circuit is carrying a very heavy flow of real power, the accompanying flow of VARs will cause a voltage decrease at the receiving end which may require the supply of VARs at that point in the system to boost the voltage.

These VAR and voltage phenomena are particularly important considerations in establishing system design requirements and allowable system operating procedures. When systems are being designed, transmission engineers may specify the installation of various VAR compensators to generate additional VARs to boost voltages or to absorb excess VARs to reduce the voltage. Shunt connected reactors will absorb VARs and prevent abnormal voltage rises for light loads. Shunt capacitors will supply VARs to support terminal voltage levels during heavy loadings. Devices such as static VAR compensators or synchronous condensers (a rotating machine similar to a generator that only supplies VARs, not MW's) are controllable devices that may be used to supply VARs at one time and absorb them at another. Voltage drops along an overhead line may also be compensated to some extent by installation of series capacitors in the line itself. These devices will automatically reduce the magnitude of the voltage change along the line.

Underground cables store more energy in the electric fields surrounding the conductors than in the case with overhead circuits. The reduced spacings between the conductor and the effective ground, the external cable covering, and by the insulating materials used with high dielectric constants, (a measure of the medium's ability to support an electric field) cause this phenomena. Therefore in cable transmission systems the heating effects due to power losses and use of circuit capacity caused by the flow of VARs are much more important than in overhead lines.

1.5.4 High Voltage Direct Current Systems

Although the vast majority of the transmission circuits and capability are ac, there are some important installations of high voltage dc systems [19, 20]. These are special situations such as the requirement for the delivery of blocks of power from remote sources to load centers and the interconnection of asynchronous systems such as the ERCOT region of Texas and the Eastern Interconnection or the interconnection of the Hydro-Quebec system to the Eastern Interconnection.

Direct current overhead circuits consist usually of a positive and negative conductor operated at high dc voltages such as ± 400 kV. The terminal stations include rectifiers and associated controls at the sending end and invertors and controls at the receiving end. Some dc circuits are designed so that the power flows may be reversed while others are intended for flows in only one direction.

In some cases where asynchronous systems are interconnected via dc, there will be only a "back-to-back" installation of rectifier and invertor without the need for an actual dc transmission line.

The advantage of dc transmission is the inherent ability in the dc system to control the level of power flow through the circuit. In ac systems this type of control is indirect in that power flows may be adjusted by shifting generation levels or effecting switching operations to readjust power flows. In an ac system the power and VAR flows will distribute themselves automatically to conform to the laws of physics that govern the behavior of the currents and voltages. In a dc installation power flows may be controlled precisely by controlling the rectification and inversion processes.

Direct current circuit capacities are limited by the thermal capacities of the transmission circuits and the capacities of the terminal equipment. VAR supplies enter the picture only in the interconnected ac systems.

Direct current systems that parallel high voltage ac interconnections may be used to reduce, mitigate or prevent the dynamic instabilities that may arise in the ac system [21]. This capability may play a significant role in a decision to use a dc link instead of ac if stability problems are important in the particular region.

In many parts of the world underwater dc cables interconnect power systems that are separated by large bodies of water. These installations are preferred over ac cables because of the desire to interconnect asynchronous systems, control power flows, and because the transmission distance may be too long to be practical for an ac cable system.

1.5.5 Subtransmission Systems

Subtransmission systems are exactly what the name implies, transmission systems that are "below" the transmission systems. They serve the function of delivering power from the high voltage transmission system to the major distribution substations. Voltage levels are less than 115 kV and greater than the usual highest distribution system voltage level. The distinctions between subtransmission and transmission varies from system to system. A 69 kV class circuit may be a subtransmission voltage in a large system with a relatively high load density while a 69 kV class circuit may be a major transmission link in a rural area with sparse load density.

The components of the subtransmission system (i.e., lines, transformers, breakers, etc.) are the same as those of the transmission system, although of a different voltage class. In utility systems where increasingly higher transmission voltage systems have been installed as the load has grown, the subtransmission circuits may parallel the high voltage circuits and become overloaded if power that is intended to flow on the high voltage lines divides and flows over the lower voltage, subtransmission circuits. In some systems this has caused subtransmission circuits to be opened at one end to avoid parallel operation with transmission circuits. This results in serving load area substations radially.

1.5.6 Underground Power Transmission

As of 1982 there were approximately 2900 circuit miles of ac underground cable in the U.S. operated at voltages of 69 kV and above [22]. Table 1.6 shows the estimated distribution of these installations for transmission voltage levels for various regions of the country. The applications are, for the most part, in densely populated metropolitan areas where it is increasingly difficult, if not impossible, to install overhead power transmission circuits.

The loading of underground cable circuits is dependent upon thermal limits primarily. These in turn are a function of the cable design, the cooling system, the thermal characteristics of the soil that the cable is buried in, and the length of the circuit. Typical cable circuit maximum ratings as a function of cable nominal voltage class are shown in Table 1.7. Ratings of overhead circuits of the same voltage class are shown in the last column for comparison [23].

TABLE 1.6

Cumulative Circuit Miles of High Voltage Power Transmission Cable in the U.S. (Estimate as of 1982)

REGION	CIRCUIT MILES			
	115-161 kV	230 kV	345 kV	500 kV
New York-NJ Metropolitan Area	700	100	200	-
Philadelphia-Baltimore-Washington, dc Area	300	200	-	-
Great Lakes Urban Areas	400	50	20	-
New England	100	-	20	-
Los Angeles	200	35	-	-
San Francisco	150	75	-	-
Urban Areas in Florida	150	50	-	-
Other Areas	100	20	10	6
Totals	2100	555	250	6

Source: "Underground Cable Systems", Course notes, Power Technologies, Inc., Schenectady, NY, 1982 revision, unpublished.

TABLE 1.7

Typical Underground Cable Ratings

Voltage Class (kV)	Typical Rating (MW)	Ratings of Typical Overhead Lines (MW
115-161	220	100 - 200
230	330	200 - 400
345	450	400 - 1000
500	700	1000 - 2500

Source: "Underground Power Transmission", Report prepared by A.D. Little, Inc., Oct. 1971, published by the Electric Research Council, 90 Park Ave., New York, NY 10016.

The four basic types of cable systems suitable for use at voltages of 69 kV and above are:

1. Oil-filled, pipe-type cable in which the cable is installed in an oil filled pipe. The oil, used as the cooling medium, is under pressure within the pipe.
2. Oil-filled, self-contained cable where the cable is directly buried in the ground.
3. Solid dielectric cables where the insulating material is solid and the cable is directly buried.
4. Gas-insulated cables where sulfur hexafloride is used as the insulating and cooling medium. These are used primarily in gas insulated substations.

The type of cable, its specific design and the heat transfer characteristics of the soil surrounding the cable in each underground installation affect the cable rating.

Cable transmission systems are generally several times more expensive to install than overhead circuits. Because of the close spacing between the active conductors and the cable sheath (or ground) the electric fields in a cable are very strong and they generate many more VARs per mile than an overhead line [24]. This means that the reactive component of the flow in the cable, the VARs, are much higher even under normal loading conditions so that cable capacity is limited by this phenomena. System operating requirements may dictate the need for VAR compensation at the terminals of the cable.

1.5.7 "Typical" Transmission Systems

From this brief introduction to the generation and transmission systems, it should be apparent that there are many combinations of components that may make up a bulk power system. As a matter of fact, there is no single "typical system" pattern that represents the large variety of electric utilities in the North American systems.

Northeast

In the northeastern portion of the country, there are EHV circuits used to interconnect systems as well as to permit the importation of blocks of power from Canada. Much of the EHV network is essential to the operation of the three centrally dispatched power pools, PJM, NEPOOL and the NYPP. Along the seaboard the urban areas have very high load densities and contain underground transmission to deliver power to urban centers. The load densities in the other areas away from the large urban population centers on the seaboard are much less and the transmission systems are used to connect power generation stations into the network, provide interconnection capability and enable express delivery of Canadian energy to the U.S. systems.

Southeast

In the Southeast regions load patterns are mixed. Generation stations are located throughout the region and the EHV network has grown to interconnect the region, facilitate power transfers and the operation of centrally dispatched, holding company operated power pools, and connect generation to load areas. EHV lines from southern and central Florida allow the interchange of power between the systems within the state and the states to the north.

Midwest

In the midwest and Great Lakes areas the systems are interconnected with an extensive EHV network. Major load areas are concentrated around the Great Lakes region industrial belt. An extensive EHV network permits the integrated operation of the systems within the American Electric Power Company.

Texas

In the Texas area the major load areas are near the Houston and Dallas areas and the other cities in the state. The transmission network is a 345 kV "backbone" system that ties together the major systems in the state. The western part of the state is served by lower voltage lines. The systems that belong to ERCOT are interconnected asynchronously to the other systems in the Eastern Interconnection by means of dc ties.

Plains States

In the plains states the load centers are generally located in or near widely spread urban areas. The transmission is more sparse and has been installed primarily to interconnect load and generation. In the northern portion of this central region of the country there is transmission installed to Manitoba and to the west of Minnesota to connect remote generation to load areas.

In the middle of the country, from the Texas Panhandle north, both the population and electrical load densities are low. Transmission is generally of a lower capacity and has generally been installed to interconnect load and generation. There are few EHV circuits in this region.

Western States

The western systems are interconnected extensively. Figure 1.4 shows only the EHV and major dc circuits. The western areas are in fact interconnected with a transmission system that approximates the shape of a giant "doughnut." The eastern circuits closing the loop are lower voltage than those on the western side. The

EHV lines into Canada connect the Canadian hydroelectric generating plants to the western U.S. systems. A ± 500 kV dc interconnection provides an express transmission path between the hydroelectric resources in the Pacific northwest and the major load centers in southern California. Southern California is interconnected with areas in Arizona and New Mexico that contain major generating plants.

The operating practices, transmission related technical problems and transmission limitations faced by systems in the various regions differ because of these different system configurations and area patterns of load and generation.

1.6 DISTRIBUTION SYSTEMS

There are approximately 100 million customers of the electric utility industry in the U.S. [13]. All but about one percent are served from a distribution system. The distribution system is an extension of the transmission and subtransmission systems designed to transmit power to serve the ultimate customers. The transmission system delivers "bulk power" to the substations where the distribution system actually "distributes" the power to the various loads. The distribution system voltage levels include all of those below the range in the subtransmission class.

It is not uncommon to have major industrial customers served directly from the subtransmission system. In these cases there is a separate substation dedicated to serving this firm and the customer has his own internal distribution system. The substation may be owned by the utility or the industrial firm. Metering, protective and switching apparatus would be located in this station.

The distribution system is subdivided into "primary" and "secondary" systems. Figure 1.8 illustrates the interfaces between the subtransmission, primary and secondary distribution systems. The subtransmission system delivers power to the distribution substation where a transformer reduces the voltage to that of the primary system. The primary distribution system includes all of the facilities between the distribution substation and the distribution transformers. The secondary distribution system includes the distribution transformer and the circuits up to the service entrance point of the ultimate customers.

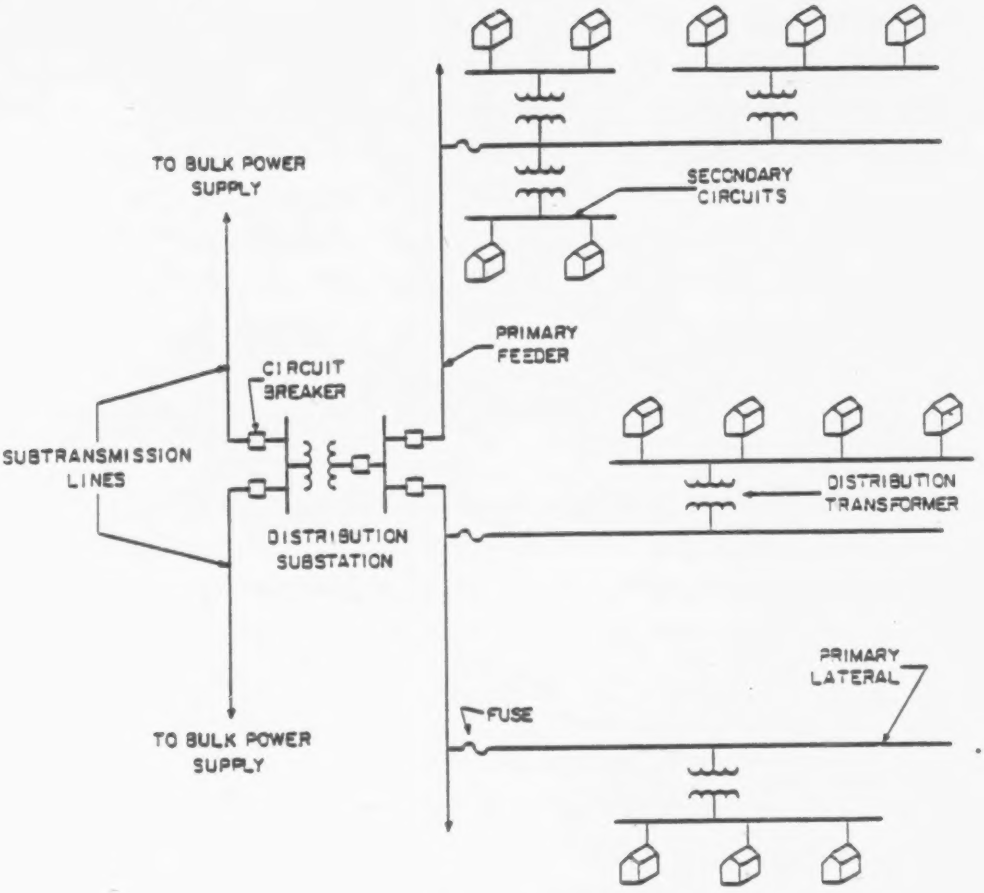

TO BULK POWER SUPPLY
SECONDARY CIRCUITS
PRIMARY FEEDER
CIRCUIT BREAKER
SUBTRANSMISSION LINES
DISTRIBUTION TRANSFORMER
DISTRIBUTION SUBSTATION
PRIMARY LATERAL
FUSE
TO BULK POWER SUPPLY

Figure 1.8 - Interface Between Subtransmission, Primary and Secondary Distribution Systems

The subtransmission and primary feeder circuits are three phase circuits. Primary lateral circuits, branching off of the primary feeder circuit, are usually single phase, as are the secondary circuits which deliver power to the consumers' service entry points. Secondary circuits are laid out to serve groups of customers in a neighborhood. Note that the system shown on Figure 1.8 is serving these customers with a radial feed pattern. That is, power is only delivered to the secondary systems through one path.

The complexity in the subtransmission and distribution circuit configurations arise naturally out of the desire to supply more reliable service. For example, the load area shown on Figure 1.8 might by tied to another substation through a primary feeder circuit and the switch that was normally open. The tie switch could be closed in case that service to one or the other of the substations was interrupted by the opening of a subtransmission circuit. The configuration may be even more reliable by having major distribution substations fed by at least two subtransmission circuits at all times. Then, when and if a circuit fault should occur on any one subtransmission line, it could be removed from service automatically by the protective systems without interruption of service.

1.6.1 System Configurations and Customer Classes

This whole concept of providing reliable service permeates the designs found in the various primary and secondary distribution systems. The primary system contains the higher range of distribution voltages, typically between 2.4 and 34.5 kV. Small industrial customers and commercial customers may be served directly from the primary system with three phase or single phase service. The lower voltage portion of the distribution system, the secondary system serves the residential and small commercial customers at voltages that are typically below 600 volts.

Load categories and the size range of typical loads are:

Industrial	10 to 100 MW
Commercial	200 kW to 10 MW
Residential	5 to 25 kW per residence

Other customer classes may include agricultural loads, irrigation loads, street lighting and service for municipal uses.

The service to residential customers may be overhead or via underground systems, known as URD systems standing for underground residential distribution. Overhead circuits are less costly to install but require poles and rights-of-way and are subject to outages caused by weather, falling tree limbs and so forth. URD systems are more costly to install but are protected from the elements.

Commercial loads are frequently served by systems which provide alternate feeds through different primary circuits. The degree of redundancy depends a great deal on the size and relative importance of reliability to the load. A shopping mall in a suburban area, for example might be fed by a looped primary system where the load is served by two primary feeders connected to the distribution transformers. The commercial load in a downtown area in a major metropolitan center may require the installation of an underground, secondary network configuration such as that shown in simplified form in Figure 1.9. This complex secondary network provides redundant feeds to the commercial customers via the secondary network and the multiple primary feeders delivering power to the network.

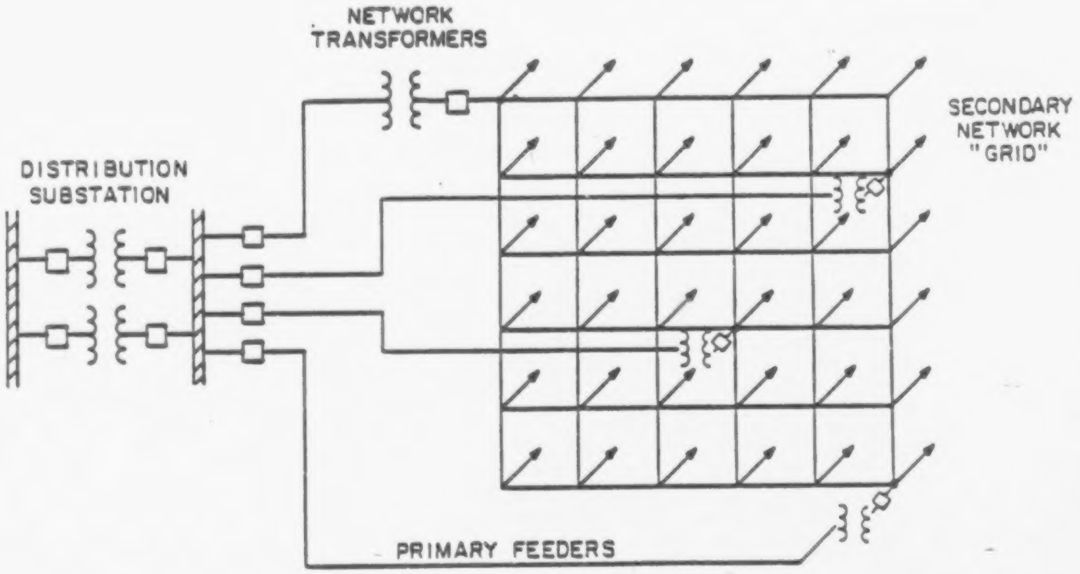


Figure 1.9 - Secondary Network (Simplified)

Protective systems in the distribution systems range from circuit breakers in distribution substations that open automatically when faults are detected by the protective relaying system all the way to fuses on secondary distribution circuits that open circuits subject to overload currents. A major task in the operation of the distribution systems is the design and operation of the protective systems. Many of the breakers and switches applied in distribution circuits are manually operated devices so that much of the circuit switching required to restore service and to remove circuits for normal maintenance is done manually. Service crews are dispatched to accomplish this with the aim of minimizing service interruptions since remotely controlled breakers and switches are rarely used in distribution systems.

The outages experienced by retail utility customers are usually caused by weather related failures that occur in the distribution systems. In terms of customer-hours interrupted, approximately 80 to 85% of total interruptions occur in the distribution system. Sleet storms, tornados and other storms that cause widespread damage to the tree limbs overhanging distribution circuits may cause distribution system outages requiring a week, or longer, to restore all of the interrupted customers.

Automated distribution systems with remotely operated, automatic and controlled switching operations may improve this situation in the future and reduce outage durations experienced by retail customers. It will not happen overnight, however, as the distribution systems are very extensive and will be costly to upgrade.

1.7 INTERCONNECTIONS

The U.S. and Canadian utilities are organized into nine regional reliability councils under the North American Electric Reliability Council (NERC). The nine regions are shown on the map on Figure 1.10. As of the fall of 1987 the total capacities and peak loads of each are as shown on Table 1.8.

Within each interconnection there are one or more control areas, each of which is defined as that portion of the interconnection to which a common generation control scheme is applied. There are over 140 such areas in these systems. These control areas assist in the application of the automatic generation control systems discussed in subsequent chapters. Their existence is essential to the effective control of power interchange between systems. They do not impede these interchange levels, but aid the operators in keeping the flows within circuit ratings.

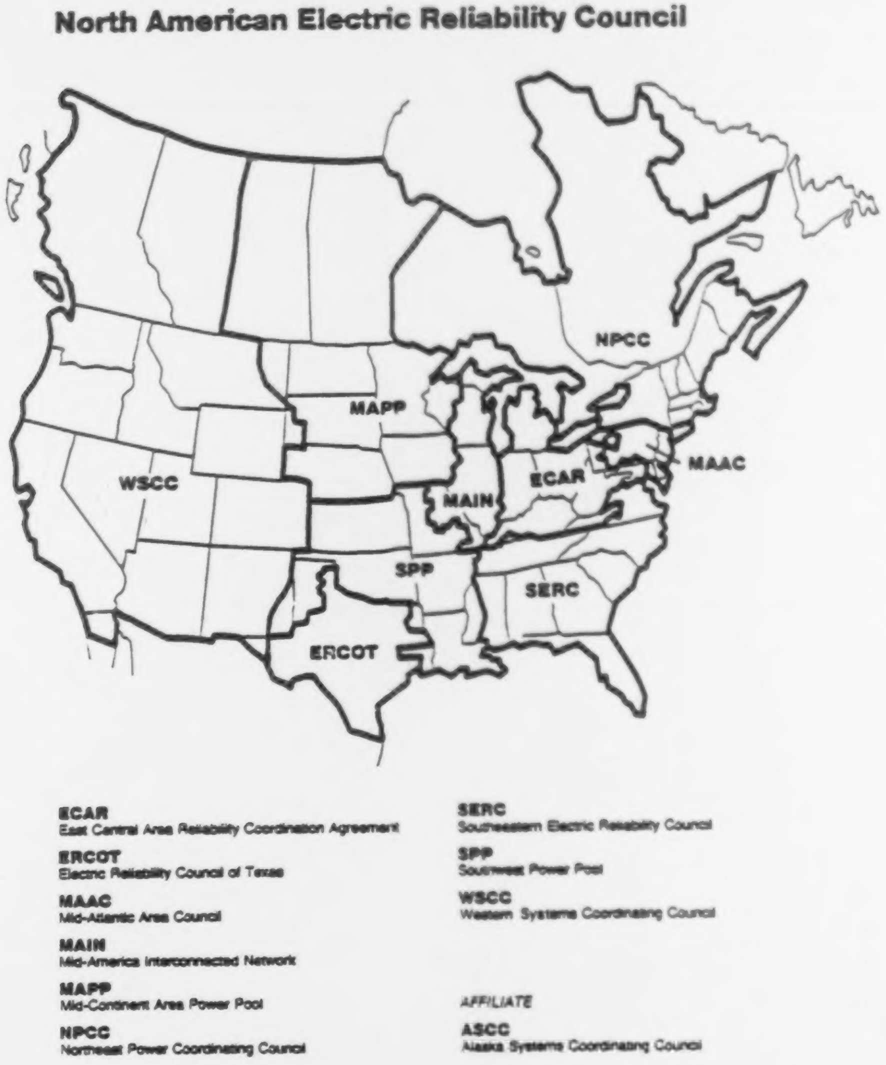

North American Electric Reliability Council
NPCC
MAPP
MAAC
WSCC
ECAR
MAIN
SPP
SERC
ERCOT
ECAR
East Central Area Reliability Coordination Agreement
ERCOT
Electric Reliability Council of Texas
MAAC
Mid-Atlantic Area Council
MAIN
Mid-America Interconnected Network
MAPP
Mid-Continent Area Power Pool
NPCC
Northeast Power Coordinating Council
SERC
Southeastern Electric Reliability Council
SPP
Southwest Power Pool
WSCC
Western Systems Coordinating Council
AFFILIATE
ASCC
Alaska Systems Coordinating Council

Figure 1.10 - Geographic Areas of the Nine Regional Reliability Councils of NERC

TABLE 1.8

NERC Reported Capacities and Peaks As of Summer 1986

Region	Capacity (MW)	Peak Load (MW)
ECAR	95,201	69,606
ERCOT	43,386	39,335
MAAC	47,626	37,564
MAIN	45,351	35,943
MAPP*	35,054	24,935
NPCC*	111,213	85,161**
SERC	132,168	105,570
SPP	65,102	47,123
WSCC*	142,885	91,768

* Includes Canadian Areas
** Winter peak for 86/87 shown for NPCC

Source: 1987 Reliability Assessment, NERC, Princeton, N.J., September 1987. [20]

The benefits of interconnected operation are numerous and include:

- better frequency control (i.e., tighter frequency tolerances),
- access to reserves in the interconnected systems,

- mechanisms for the exchange of operating data, and
- the opportunity to develop interconnection-wide operating guides and standards.

The disadvantages are few and those cited only seem to include the costs and time required to effect the agreements required. Interconnected systems' operations appear to be very successful with close frequency control. The adherence to a close frequency standard permits the automatic generation controls to function properly.

CHAPTER II

CHAPTER 2

ECONOMIC OPERATION OF GENERATION CONTROL AND INTERCONNECTIONS

2.1 INTRODUCTION

The economic operation and control of the interconnected power systems represents years of evolution and development. Modern electric power control centers make use of high memory capacity, high speed digital computers and communications systems to dispatch and control the interconnected power systems to:

1. Balance the generation and load to control the frequency.
2. Provide for reliable and secure operation of the bulk power systems.
3. Schedule the generation resources for minimum operating cost [14].

The order of priority is as shown. Frequency control and generation control for system security are discussed in Chapter 3. They are more important in the overall operations than economy. That is not to downgrade the importance of economic operation, but the systems must be controlled to supply electric power at the correct frequency and voltage for customer use on a secure basis.

This chapter considers system operations and the role of system interconnections. Economic dispatch, generation control and the organization and operation of the interconnected system are all interrelated. They are important areas to be considered when assessing the technical problems that are significant in any potential industry restructuring that may disrupt the current control systems and arrangements. The current arrangements work well, due in a large measure to the voluntary cooperative efforts of the system operators. This cooperation is necessary to achieve the level of reliable system operation that exists in the current industry structure [25].

2.2 SYSTEM OPERATIONS

System operators, the dispatchers, control center staff and operations planners must decide:

1. How much generation to operate to meet the expected demands.
2. What specific units to run.
3. How these units should be scheduled so system production costs are minimized while providing for system security.

The first concerns loads and expected load patterns. The second item refers to what is known as "unit commitment" and is similar to the types of scheduling processes that take place in a manufacturing operation that has excess capacity for the production level required. The third item is the economic dispatch of the generation, but it must include the system security considerations that take priority over purely economic decisions.

Maintenance scheduling of generating units affects system operations as well. Units must be removed from service periodically for inspection and for making scheduled repairs. Maintenance scheduling takes place in a longer time frame than unit commitment and economic dispatching and is frequently done on an annual basis.

2.2.1 Load Patterns

The total system demand that must be balanced by an equal amount of generation includes the expected system load, the requirement for supply of power outside of the system recognizing any power imports (i.e., the net interchange scheduled) and the system transmission losses. System loads are always changing. Load patterns tend to repeat themselves and will vary not only with the time of day, but with the season, the area's economic conditions and the weather. Figure 2.1 shows a weekly load curve for a U.S. utility system. There is a certain amount of load, denoted as the "base load" that exists all week long. The intermediate and peak loads occur because of the nature of the living, economic and industrial patterns of the area [26].

System operators forecast short term load patterns to decide how much capacity will be required. This has to be done well in advance of the expected needs so that required units may be brought up and put on line in time. The total generation capacity that is actually operated must be large enough so that the peak load demand will be served, plus provide an operating reserve (i.e., a "spinning reserve") to be able to handle unexpected peak loads, the sudden loss of generation, or the loss of a major transmission circuit. Figure 2.2 shows the type of pattern that results when the system operators have satisfied the unit commitment requirement.

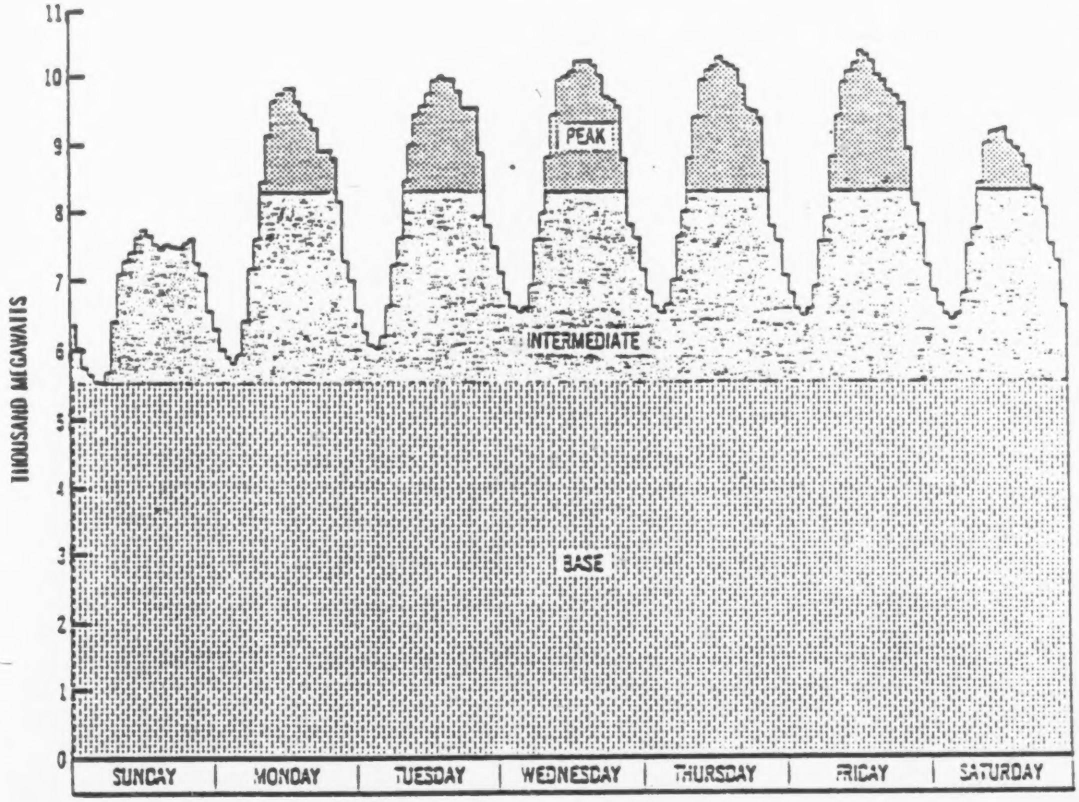


Figure 2.1 - Weekly Load Curve

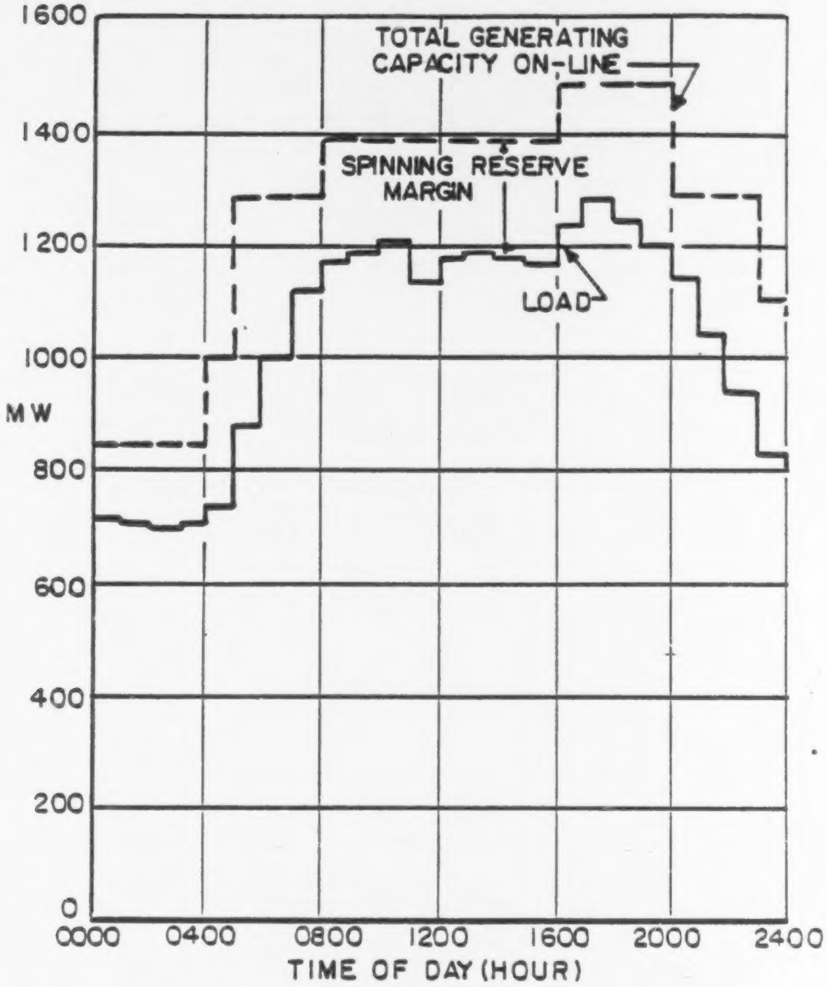


Figure 2.2 - Typical Daily Load Pattern and the Total Generating Capacity Committed Including the System Spinning Reserve Margin

The first step involved in these operating tasks is to forecast the load patterns. Fortunately, system load patterns tend to evolve slowly and operators can rely on the repetitiveness of these patterns to predict load shapes and magnitudes. Statistical modelling methods have been developed which make use of past data and take into account the expected weather patterns to predict not only peak loads, but the expected chronological shape of the load.

2.2.2 Unit Commitment

The next step in the scheduling of the available resources is the establishment of a unit commitment plan for the generation resources available [27]. The ideal unit commitment schedule is one which meets all of the specified reserve requirements and operating restrictions and supplies the energy required for the scheduling period at a minimum total operating cost.

The practical solution to this problem involves consideration of all of the resources, hydroelectric generation, steam and combustion turbines, contracts and interchange arrangements with interconnected utilities and non-utility generation from cogenerators and qualified facilities on the system. It is not an easy scheduling problem to solve in such a way that the optimum production cost schedule is ensured. There are many practical limitations on the operation of various resources that prevent them from being scheduled freely and other operating constraints that must be observed. These include:

1. The requirement for the gradual heating up and cooling down of large units.
2. The requirements at minimum load conditions where some units must be operated at their minimum loading limits (usually ≥ 25 to 35% of the unit rating).
3. The restrictions on the rapid changing of load levels for larger steam units (usually ≤ 3% of the unit rating per minute).
4. Availability of crews to start units.
5. Restrictions imposed by local environmental regulations that may limit the total discharge of pollutants in an area.
6. The need to observe the constraints imposed by long term contracts for fuel and/or electric energy interchange.

In addition the transmission network limitations may require that generating capacity in certain areas be online to provide sufficient resources in case of transmission circuit outages.

Figure 2.3 illustrates the form of the total production cost characteristic of a steam turbine generator. These costs include the cost for fuel and incremental operation and maintenance charges that may be expressed as a charge per hour and/or per MWh. In addition the unit's operating costs will include costs for starting the unit. These include the cost of fuel for heating the unit, extra crew costs associated with starting water treatment systems and flue gas desulfurization systems. For a large unit that has been shut down for maintenance, startup charges may exceed $100,000 [28].

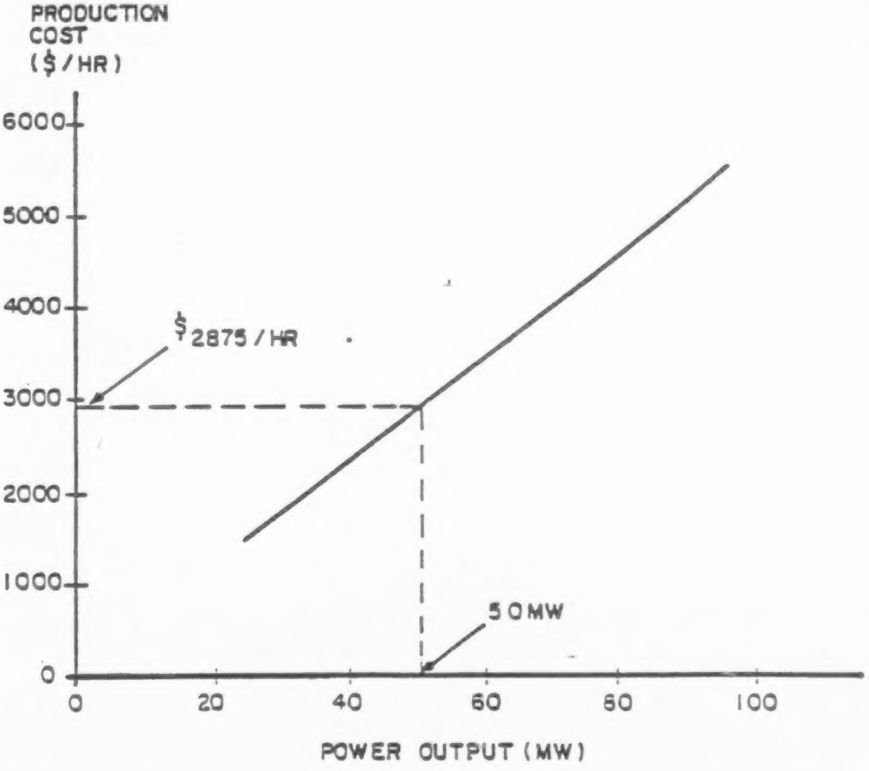


Figure 2.3 - Steam Turbine Generator Production Cost Curve

Unit commitment schedules computed to minimize total period production costs usually result in the commitment of the larger units to serve the base loads with the less efficient, more costly units being added as the load levels increase during the day. The least efficient and most costly units to operate are usually simple cycle combustion turbines and they are run primarily for peaking duty. The procedure is reversed as the load falls during the day.

Unit commitment schedules are usually developed daily and will be redeveloped after major plant outages. System dispatches may change unit commitment schedules during the day to permit economic interchanges to take place.

2.2.3 Economic Dispatch

Once the unit commitment pattern has been set, units that are online are economically dispatched. This involves determining the generator operating points at each time interval and load level such that the load is satisfied at a minimum total production cost rate. Economic dispatch schedules are recalculated frequently at periods of 5 to 10 minutes in most energy control systems. The easiest case to consider is the system composed of only steam or combustion turbines where the individual unit production cost characteristics are similar to the one shown on Figure 2.3.

The slope of the unit's dollar per hour versus MW output characteristic when plotted against the unit's output is known as the incremental cost characteristic. It gives the cost in dollars per MWh of the next MW of output of the unit. The optimum operating points of the generators are at that point where the incremental operating costs of all units are equal. At that point the next MW needed will theoretically cost the same no matter which unit produces it. This theoretical approach must, of course, recognize the practical limitations of maximum and minimum loading levels of the units, the maximum rate of change permitted for the generator loading levels, and the operating constraints that may be caused by transmission system loading limits.

It is this concept that gives rise to the well known system incremental cost that is widely used in the literature when scheduling, wheeling costs, etc., are being discussed [14, 29]. There are numerous complications in economic dispatch and scheduling that complicate the practical solution as well as the marginal cost concept. The first has already been discussed and is the result of the unit commitment procedure. (Actually the economic dispatch is a subset of this cost minimization procedure.) The unit commitment schedule results in subdividing the time intervals into periods during which the array of units on line is fixed. The incremental operating cost rate during any one of these intervals will increase as the load level increases. When the array of units running changes, this function also changes. The result is that over the period of a day, incremental cost rates (i.e., the "system lambda") may both rise and fall as the system load level increases.

When any of the generators or transmission circuits are constraining (e.g., units are at their operating limits or transmission circuits constrain the generation schedules), theoretically this incremental cost rate changes with location in the system. It is a common practice in the industry to refer to a single system incremental cost that is the incremental cost of the next MWh produced by unconstrained generating units.

Another complication is one due to the effect of transmission losses. In a system with widespread generation resources and load centers the losses in the transmission system may influence the economic dispatch. In these systems the operators must include what are known as incremental transmission loss coefficients in the scheduling algorithms. These coefficients are the incremental change in transmission system losses for an incremental change in power output from a generator. They are determined by analyzing the flow of power and VARs in the network and recognizing that the shifting of a MW of generation from one location to another affects not only the generation production cost rates but may also affect the total demand to be met by changing the transmission losses in an incremental manner.

In systems with both hydroelectric units and steam plants, the dispatch procedures must recognize the effects of the water usage requirements on the schedule. If the hydro plants have sufficient water storage capacities, the hydro plants will be scheduled to minimize the total production costs of the system for some period (typically a week) by using the hydro generation to reduce the costs of operating the steam plants. Typically this results in some portion of the hydro plant being run to serve base loads with the remainder being used to reduce the peak loads to be served by the thermal generation. The exact schedules will depend on the balance between the storage capacities available, the run-of-river component of the hydro plants, the water use requirements and the water rate versus power generation characteristics of the hydroelectric plants. The coordination of the hydroelectric plants and the thermal plants may be a simple task for the operators in a system with only a single hydro plant or it may be very complex where there are several complex watersheds to be considered. The interaction of the hydro plant operation and thermal plant schedule will also affect the determination of the optimum unit commitment pattern.

Economic operation is further complicated by contractual terms for both fuel supplies and the interchange of electrical energy with interconnected electric utilities. These areas are hard to categorize into "typical" patterns because the power system scheduling procedures must recognize the terms established by the various contracts involved.

One type of fuel contract that has been fairly common is the type of supply contract that contains a "take-or-pay" provision where the purchaser is obligated to purchase a minimum amount of fuel in a given period whether or not delivery is actually requested. These are similar to the take or pay supply contracts in the natural gas industry. In the purest sense and ignoring any complications caused by fuel storage facilities, the obligation to pay for a set amount of fuel by the electric utility represents a classical "sunk cost." The utility's total operating costs thus include a fixed component; the units burning this fuel will have a more-or-less fixed operating cost for some interval. This contract turns the thermal unit into a hydro-like plant with characteristics similar to a hydro-electric plant with storage as far as economic dispatch is concerned. There is a fixed amount of primary energy resource (the fuel in this case, not the water) that should be scheduled in such a fashion that the controllable total production costs are minimized during the interval.

Contracts for interchange may be quite simple such as a fixed charge for capacity plus a charge for energy at a given rate, or they may be quite complex involving charges based on avoided costs of the purchasing utility or energy charge rates which are ratcheted based on the maximum power demand in a month. The economic scheduling of the system may in some cases, be determined by the terms and conditions of contracts. This is frequently the case in municipal utilities that have some local generation and contracts for partial requirements from one or more interconnected utilities. In some situations that are particularly difficult to schedule, one of the contracts may have a ratcheted energy rate that is retroactively based on the monthly maximum demand level. In a dispatch determination by the purchaser's operators the purchase levels have to be balanced against the costs of local generation recognizing the ratchet effect.

Fuel supply systems may play an important role in determining the economic dispatch of the generators in the system. It has been usual in the past to decouple the fuel supply scheduling from the hourly economic operating dispatch of the generators by tacitly assuming that the fuel requirements determined by the economic dispatch could be satisfied by the fuel supply system. The fuel supply system and generation system should be treated as parts of one larger system that should be scheduled simultaneously.

2.2.4 Effects of the Transmission System on Economic Dispatching

One effect of the transmission system on economic dispatch procedures has already been noted (i.e., that of constraining the output of a unit or plant). When incremental transmission losses are significant, they should be recognized in the dispatching algorithm. When this is done the operators can determine the incremental cost of delivered power at various key interconnection points in the network. Some larger systems have interchange contracts that specify that these incremental costs including transmission losses will be used to determine prices.

The transmission system plays another key role in the economic dispatch process. Generation schedules will be determined that are "off economy" (in the sense that they are not the optimal economic schedules) in order to avoid potential cascading outage situations [14, 30 - 33]. Power flows in ac networks are generally not controllable in the same sense that gas pipeline or water pipeline flows are. There are no simple valves that may be used to regulate the flows on particular circuits. What is controllable directly is the level of generation at a particular power station. These generation levels will indirectly affect the flows on specific circuits and, therefore, provide the power system operators with a degree of flow control.

Most utility control centers have, or are implementing what are known as "security constrained economic dispatch" methods. In these techniques the system is operated in a defensive mode where "credible contingencies" are not allowed to cause substantial generation-load imbalances, network element overloads or out-of-range voltage levels on the system. This is done by using a network model (i.e., a load flow) to examine the "what might happen if..." cases that result from a given economic dispatch, and then modifying that dispatch so that the resulting schedule will not cause potential operating problems in case of the credible contingencies. This procedure places a higher priority on system security than on operating economy. Security constrained schedules may be computed at intervals of 20, or 50 minutes, less frequently than the economic dispatch and more frequently than unit commitment schedules.

The security constrained dispatch procedure is straightforward to implement. The exact determination of "credible contingencies" is subjective. There appears to be general agreement that all possible single contingency events should be considered so that failure of any single generating unit or transmission line will not initiate a cascading sequence of outages. Many systems are operated more conservatively in that credible outages include combinations of two events such as the failure of a major circuit at the same time as an outage of a large generator (i.e., they consider double contingencies.)

2.2.5 Summary of System Operating Considerations

We have taken a brief look at what is a complex technical area. The discussion is intended to provide a brief, non-technical overview. For simple arrays of generators economic dispatch is straightforward once the unit commitment has been established. At any given time the system is operated such that the incremental production cost rate is the same all over the system.

Once energy storage in any form (fuel or water) is introduced, the economic operating problem becomes more complex and the focus of the scheduling problem becomes one of minimizing total production costs for some interval rather than merely finding the proper level of system incremental production cost. Contracts for interchange may have a similar effect if they introduce requirements to schedule the system over a time span.

The transmission network plays a significant role in the economic scheduling of power generation. Economic schedules may include the recognition of incremental transmission losses. Transmission systems play a key role in the determination of operating schedules that ensure system security when constrained economic dispatch techniques are used.

2.3 EFFECTS OF NON-UTILITY GENERATION ON SCHEDULING AND DISPATCH

Non-utility generation includes:

- smaller dispersed generation sources (e.g., wind farms, solar photovoltaic, etc.) connected on the distribution system,
- self-generation connected in parallel with the utility,
- PURPA defined Qualified Facilities (QFs), and
- independent power producers (IPPs) supplying power to the utility.

Small dispersed power generators are usually not dispatchable and are treated as load reductions when system operators are scheduling generation and dispatching.

Self-generation is usually in a commercial facility or industrial plant. Normally it is operated in parallel with the utility system for standby supply in case of an emergency shut-down. It is not expected to supply power to the system, and is therefore not usually considered in the utility dispatch. If it is a large installation, the utility may have to increase the amount of spinning reserve scheduled on the utility system to guard against the sudden imposition of load in case of a sudden loss of the self-generator's in-house capacity.

QFs are paid for their power production at "avoided cost" rates. They affect the utility's economic dispatch and possibly the unit commitment if the capacity supplied is large compared to the minimum load levels on the daily load cycle. In small quantities the utility dispatcher can treat the QF operations as load reductions. "Avoided costs" are calculated in different fashions, depending upon state regulations.

In some localities, notably in Texas and California, the total capacity of industrial cogenerators has approached the point where the utility light load dispatch is seriously affected. This happens because the most efficient utility steam plants have normal minimum load limits of about 40 to 50% of their maximum ratings. These units were not designed to be shut down overnight. Therefore, when the total non-dispatchable generating capacity becomes too large, the load remaining to be served by the utility generation at night time minimum load levels is too low to be supplied by the utility's normal array of steam units. The exact point at which this becomes a problem depends on the specific array of utility units and the level of remaining minimum load to be served. It is possible to shut down the more efficient units for longer periods to alleviate this problem, increasing the utility's operating costs.

IPPs are relatively rare to date but will become more prevalent as utilities seek additional capacity. Existing IPPs are usually the result of the divestiture of a former utility power plant. They are operated as an adjunct of the utility with exact terms for control established by the agreement between the IPP and the utility.

2.4 POWER INTERCHANGE

Power is frequently interchanged between interconnected systems for a variety of reasons. Scheduled interchanges are usually undertaken for reasons of operating economy or requirements that arise due to emergencies. Economy interchanges may be the result of centrally dispatched power pool operations or hour-by-hour negotiations between dispatch centers. Longer term arrangements are made between system operators or result from contracts between utilities for exchanges or wheeling arrangements. Inadvertent interchange takes place as a result of imperfect generation control system actions, failures or other unplanned events that require time to correct.

2.4.1 Economy Interchanges

Economy interchange arranged between dispatch centers is of two types. Frequently used industry jargon separates these into economy "A" or "B" transactions. "Economy A" transactions involve the sale of energy from units online, usually for an hour. "Economy B" transactions involve a longer time period and may involve changes in generating unit status, bringing units online to sell their output or shut down capacity if an economic purchase can be negotiated.

Pricing of economy A interchange is frequently based on the difference in marginal production costs in the two systems involved [14]. For a system that currently has a high incremental production cost rate, the purchase of economy A energy may be more economic than to increase its own generation to serve an expected load increase. If the selling system is agreeable, the price for the energy may be based on the incremental and decremental cost rates of the two systems. A common pricing formula is one that prices the energy at one half of the sum of incremental and decremental cost rates. This results in the seller receiving all of his incremental production costs and one half of the purchaser's savings. There are other pricing schemes in use where, for example, sales might be offered at a level that includes a fixed profit margin for the seller.

Arrangements for economy B transactions are a little more involved since the longer term interchange may involve the recomputation of one or both of the unit commitment patterns of the two utilities. An economy B transaction is usually based on the difference in total production cost that would result from the transaction. Pricing practices will include the cost of starting units as well as the added production costs involved in an economy B sale.

In any situation where a dispatch center is involved in more than one economy transaction during the same time period and prices are based on incremental costs, the order in which the transactions are performed may well affect the price. It is usual to find transaction priorities established on a chronological order basis. This situation where the price for a commodity (i.e., electrical energy) increases with the level of production in the short term, reflects the true operating cost changes in a generation system. It is different from the situation in a manufacturing facility where short term marginal costs may decline with increased production levels.

When interchange transactions involve more than two utilities the number of possible arrangements increase. Interchanges between systems separated by one or more intervening systems may be made "by displacement" or "simultaneous buy-sell" transactions. For example, suppose systems A, B and C were involved in a transaction where A wished to purchase from C, but system B was physically and electrically in the middle. A displacement type of transaction would have B purchasing from C and selling to system A. Pricing for a displacement transfer would normally be done on the basis of the incremental cost differences in the systems. If a split savings pricing method is used, the order of the transactions may be important and more importantly, the price level may be altered considerably if the incremental production cost rate of system B is out of kilter with the other systems. What started out as a large savings for the ultimate purchaser may end up as a minor improvement in the purchaser's production costs.

2.4.2 Wheeling

The other general method used for multiple party economy interchange is for the intervening utilities to sell wheeling services. These are also quite common arrangements with various pricing schemes used to set wheeling rates.

Generally the interconnected utilities have mutually agreed to use the notion of "contract paths" for transactions. In simple terms two utilities may engage in a direct interchange arrangement without paying wheeling charges if one or the other or both own (or have control of) transmission capacity between the two systems that is at least as great as the magnitude of the power to be transferred. This type of arrangement avoids wheeling related problems by ignoring the physical fact that the interchanged power will generally flow over a multiplicity of intervening circuits, ignoring ownership considerations. These arrangements have generally worked up to the point where the interchange flows begin to cause significant power losses in other systems or use transmission capacity needed by its owner.

This leads naturally to the problem that has been come to be called the "loop flow" problem. Because many of the systems are so closely tied together electrically by the interconnections, power flows will flow over unintended transmission paths and may cause actual or potential operating problems. For example, a large power interchange arranged between an eastern and a midwestern utility will divide over the available transmission circuits with the result that a substantial portion of the flow would probably be over circuits in Canada. These loop flows may cause operating difficulties for the intervening systems, affecting voltage levels and utilizing transmission capacity needed by other systems. Problems of this nature are solved by the close coordination of the utilities operating on a major interconnection. There is at present a movement towards the development and implementation of a system for the rapid exchange of operating data on a real time basis (i.e., for currently existing conditions) between major control centers. This will assist the operators in monitoring the system conditions, in avoiding serious problems and in developing agreements to avoid this sort of difficulty.

Long term supply contracts form another basis for the interchange of power and energy. The terms and conditions vary, of course, with the specific agreement. Systems will interchange energy under a contract based on selling energy produced by the system's total capacity or on the basis of a specific unit's output. There are diversity interchange agreements calling for the bilateral exchange of power and energy during different time periods. Contracts may be made between large utilities and smaller, perhaps municipal systems for the supply of a major portion of the purchaser's requirements. Contracts exist between non-utility generators and local utilities for the sale of power and energy. The 1978 PURPA legislation has resulted in many contract sales to utilities by these non-utility sources.

There is no simple classification of pricing schemes for these long-term of interchange agreements. With the exception of the PURPA based agreements, the contracts are drawn between the parties and contain various types of rate schedules. Many, if not all, are subject to regulation by the FERC.

2.4.3 Inadvertent Interchange

Inadvertent interchanges are a natural consequence of the interconnected operation and operating guidelines and practices are designed to minimize their occurrence. The individual systems keep track of the inadvertent interchanges and return them in kind, MWh for MWh at similar levels of the load cycle [25]. Inadvertent interchanges taking place during periods of high cost production are replaced during similar periods. That is, inadvertent flows that take place during peak load periods are returned during another peak period. This generally results in an equitable economic balance without the necessity of intersystem billing for these interchanges.

2.5 POWER POOLING ARRANGEMENTS

The growth of interconnections fostered the development of various types of power pooling arrangements designed to facilitate the growth of the utilities on a coordinated basis and to promote operating economies. There are presently several types of arrangements. These include (1) centrally dispatched power pools, (2) pools that involve coordinated planning and establishment of operating guides, and (3) pools that have extended the agreements between the interconnected companies to establish and use power broker schemes to achieve production cost economies.

Centrally dispatched power pools are characterized by the establishment of a central control center that acts as the chief dispatching office of the pool and is responsible for coordinating the operations of the pool members' generation and transmission systems. They are composed of utilities with generation resources. There are three well established centrally dispatched pools in the U.S. that are made up of non-affiliated utilities, PJM in the Pennsylvania-New Jersey-Maryland area, the NEPOOL organization in the New England states and the New York Power Pool (NYPP) in the state of New York. There are centrally dispatched pools composed of the operating companies owned by a utility holding company. These include American Electric Power, Middle South, The Southern Company, Central and

South West and others. In addition a new power pool, ENEREX, has recently been established to coordinate the operations of some of the utilities in Iowa.

The centrally dispatched pools schedule the generation system operation as though the member organizations were one system, resulting in a high level of power interchange. The degree of control exerted by the pool control center varies from pool to pool as does the exact structure of the dispatch and control system. In all cases the operating savings achieved by the pooled operation are allocated to the pool member systems. This is a necessary but difficult chore because of the complexity of the intersystem billing scheme required.

In all cases the pool agreement specifies in one way or another that the individual operating companies will not have increased production costs because of the pool operation. In implementing the allocation of the savings due to pool operation, the first step is to establish the magnitude of the "savings." This is done by a reconstruction of the individual member's operating costs as they might have been if the member utility operated its own resources to serve its own load obligations [14]. (In NEPOOL this is known as the "own load dispatch," a particularly suitable term.) The operating savings due to pooled operation are then calculated for an appropriate interval (say a week) as the difference between the sum of the individual utility's reconstructed production costs and the pool's actual production costs. These total savings are then reduced to pay for the costs associated with the operation of the pool facilities and in some cases, to pay for the use of the high voltage transmission system owned by one or more of the pool members. The remainder of the savings are then allocated to the pool members based on formulae which generally split the net savings equally between the net sellers and net purchasers during the interval.

Power pools establish requirements for installed generating capacity reserves and various classes of operating reserve levels that must be maintained by the member systems. In all of the three eastern pools, PJM, NEPOOL and NYPP, any interchange transactions outside of the pool are coordinated by the pool dispatch center. The current general availability of both U.S. and Canadian energy in the eastern area means that members of these three pools are able to negotiate for outside energy purchases quite frequently.

Centrally dispatched pools have not grown beyond those mentioned for various reasons. One is the practical difficulty in establishing the specific terms of the pool agreement between potential member utilities. In some instances utilities that have approached this type of arrangement have been dissuaded by the appearance that one group of participants would possibly obtain an "unfair" advantage over another group. In other instances there have been disagreements over the use of transmission facilities. In still other cases movements towards a centrally dispatched pool have been thwarted by fear of regulatory constraints. This is a confusing point since in recent years several state commissions have encouraged the creation of new state wide pools. At the same time regulatory commissions in New England have been examining the merits of NEPOOL membership for the utilities under their jurisdictions.

The central dispatch centers do much more than arrange for coordinated dispatch. They monitor and control the region's entire bulk power system. They provide a mechanism for coordinating reserve requirements, planning functions and the collection and reporting of data as well as the enhancement of the system security.

Pools of all types have promoted the practice of joint planning of facilities on a regional basis. The exchange of information concerning load forecasts and plans plus the establishment of regional reserve requirements and operating practices all contribute to the successful operation of the interconnected systems.

2.6 POWER BROKERS

One avenue that has been followed in some regions that has the potential for achieving most of the operating savings of a centrally dispatched pool is the creation of a "power broker" system. Power brokers are regional systems set up to organize a market for the interchange of economy energy amongst the members of the broker organization. Physically the "broker" may consist of a computer program accessed by the dispatch offices of the member utilities. The staffing level required for a broker is much less than that for a centrally dispatched power pool once the member systems have agreed upon the running rules since the only function of the broker is to arrange an organized market for economy interchange transactions.

A broker may operate by allowing the member systems to post hourly quotations for the sale of economy energy and bids to purchase economy energy. From here on the operation of the broker systems vary from one to another. The simplest scheme stops at this point. The member systems are free to make use of this "bulletin board" system for information and then undertake negotiations directly with another member to arrange a sale or purchase. This simple system saves the time of the dispatchers in searching the market and gives them access to the current availability of energy and price levels.

The next step in complexity and effectiveness is to have the broker, a computer program, match up the buyers and sellers each period and issue a notification directly to the parties involved. In one system these parties are free to undertake the transaction or not with their only obligation that of reporting back to the broker data about the transaction and operating cost savings. In another implementation the matched buyers and sellers are under obligation to undertake the transaction and would be obligated to report the exceptions.

The exact pricing and matching schemes to be used have been discussed, analyzed and the subject of experiments sponsored in part by the FERC. The original broker scheme installed in Florida based the pricing scheme on matching the bids and quotes on the basis of the widest difference between the incremental production costs of the sellers and the decremental cost of the purchasers. Alternative pricing schemes include the adoption of a single hourly "clearing price" to simulate the action of commodity and stock exchange systems as well as the centrally dispatched power pool.

Theoretically, the power broker schemes are an imperfect substitute for a centrally dispatched power pool since the power broker operating agreements preclude the participants from acting both as a buyer and reseller during the same period. This has the effect of restricting the transactions allowed. In some implementations participation is completely voluntary. The occasional requirement that buyers and sellers under a broker be directly interconnected or have established a contract path also acts as a constraint on the allowable transactions. In contrast, the centrally dispatched power pools interconnections are "free flowing," and there are many interchanges that take place between remote utilities with intervening systems receiving no direct payment for wheeling.

On the positive side power brokers do offer the opportunity to achieve an overall reduction in production costs without the necessity for establishing a power pool agreement and without the expense of a pool control center. By incorporating some restrictions (e.g., members can not both be buyers and sellers at the same time, purchasers under long term contracts with another broker member can not resell the power on a short term basis, etc.) the broker agreement can be established to the satisfaction of all of the potential participants, including both the larger utilities as well as the smaller municipal systems with partial requirement contracts with the large utilities.

In viewing these "market places" it is helpful to remember that this industry has a regulated monopoly structure despite the recent entrance of non-utility generators. The creation of centrally dispatched power pools and power broker schemes have largely (if not all) been the result of utility engineers attempting to produce a product at a lower, total production cost.

2.7 INTER-UTILITY TECHNICAL RELATIONS - NERC

The NERC organization serves a number of important functions in the electric utility industry. Through their two main committees, Engineering and Operating, they foster the secure and reliable planning and operation of the interconnected electric power systems. NERC collects and publishes information about the existing and planned bulk power facilities and through the Operating Committee establishes and publishes operating guides for the system operation. The NERC Operating Manual issued by the NERC Operating Committee is a very useful source of data concerning operating guides and practices of the interconnected systems [25].

The most recently available summary of the plans and existing utility facilities is reported in "1987 Electricity Supply and Demand - For 1987-1996" issued in November of 1987 [17]. This report summarizes the data reported to NERC for the North American systems and covers demand forecasts, supply forecasts and the planned additions to the transmission system.

Figures 2.4 and 2.5 are taken from this report. Figure 2.4 shows the demand and supply situation as it existed at the time of the 1987 peak demand in each NERC region as well as the expected situation in 1996 at the time of the expected peak loads.

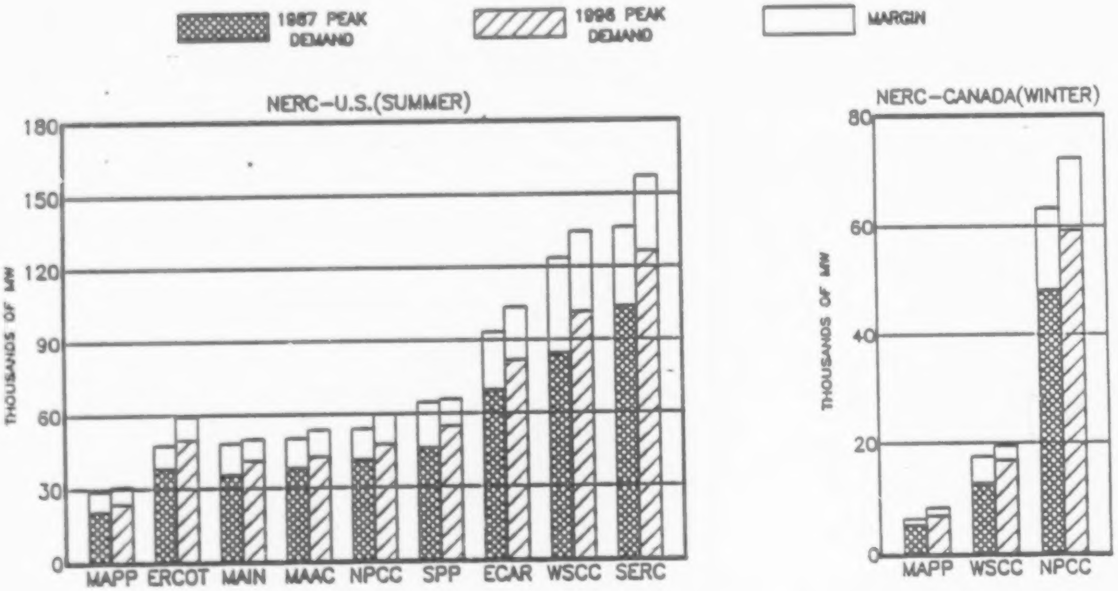
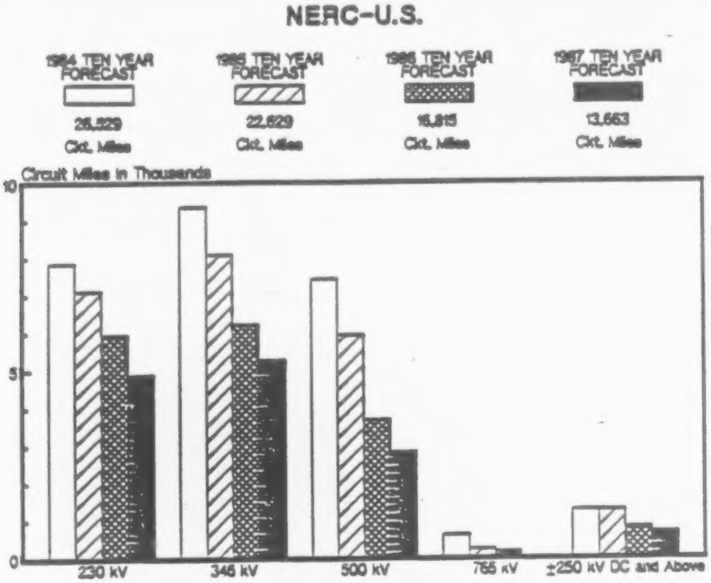


Figure 2.4 - Estimated Margins at the Time of Regional Peak Demand

Figure 2.5 shows the forecasts of the expected transmission additions of circuits 230 kV and above as reported to NERC in 1984 through 1987. According to data accompanying this figure, there were approximately 143,000 circuit-miles of transmission in the U.S. at voltage levels of 230 kV and above at the end of 1986. The 1987 forecasts for the 1987-1996 period project an increase of approximately 6% in transmission facilities. Note, however, that the forecasts of circuit additions have declined in each of the past 4 years as load growth rate forecasts and rates of construction of new generating capacity have remained low. It appears from these data that the industry may have to live with the existing stock of transmission facilities in the next 10 years.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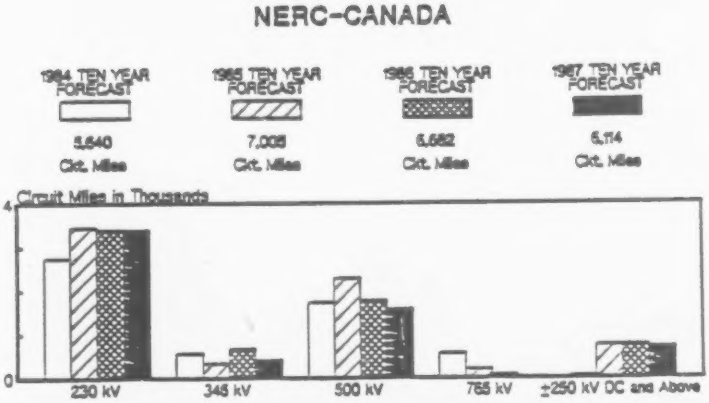
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Figure 2.5 - Planned Transmission Additions

CHAPTER III

CHAPTER 3

GENERATION CONTROL FOR FREQUENCY, VOLTAGE AND SYSTEM SECURITY

3.1 INTRODUCTION

The generation level in an ac power system must be balanced with the load demand in order to hold frequency constant. At any time there are a large number of generators operating in parallel on the power systems so that the generator governing systems must be designed to allow the units to share loads in a stable manner as well as hold constant frequency.

Voltages on the system are controlled by various devices which supply or absorb VARs. Generators are an important tool for voltage control since the level of VAR generation may be controlled by varying the generator excitation level (i.e., the generator field current.)

In an ac power system transmission line flows may be controlled by:

- shifting generation,
- adjusting interchanges with interconnected systems,
- adjusting phase-shifting transformers,
- switching the transmission network, and
- shedding load.

Under normal circumstances the first is used far more frequently than the rest. In a few systems phase shifting transformers may be used to control flows over specific circuits. In emergencies loads may be shed and portions of the system switched to reduce line flows. This chapter will discuss the use of generation power control to preserve system security. The security dispatch (or security constrained dispatch) of generation has significant consequences in the transmission capacity available.

3.2 FREQUENCY CONTROL

It is the function of the speed governors on the generating units to maintain the balance between the load and generation levels on the interconnected systems [14, 34 - 36]. If there were more generation than load, the generators would accelerate, the frequency would tend to rise, and additional kinetic energy would be stored in the rotating masses of the machines. The opposite is true when the load is greater than the generation; the generators slow down, the frequency drops and kinetic energy is withdrawn from the rotating machines. Except during emergencies such as a major outage, the governing systems keep the generation-load balance very well. Small time errors do accumulate due to these frequency deviations, but these are corrected periodically by system operators who act in concert on a regular basis to correct the accumulated time error to zero.

Three factors enter into the actions when the generation is less than the demand. One is the transient effect that takes place initially as stored energy is removed from the rotating masses of the generators. This results in a decrease in system frequency. Secondly, the total system load has a frequency response that causes the load to drop as the frequency drops ("load damping" or "load-frequency damping.") Next, the speed governing systems will increase the inputs to the prime movers of the generating units, increasing the electrical generation and bringing the load and generation into balance once again, but at a reduced frequency. The opposite sequence takes place when generation is greater than the load. Frequency increases, the load increases, and the governors reduce the generation.

Figure 3.1 shows the actions that take place on a 6000 MW, isolated system when a 300 MW unit is suddenly lost when the system load is 5000 MW [26]. The governor characteristics have a speed droop (i.e., the speed declines as the loading increases.) The speed droop characteristics required to permit stable parallel operation of the generators would have caused the frequency to decline to 59.85 Hz in this example. (The composite speed droop is assumed to be 5%, meaning that the frequency would drop by 5% as the load goes from zero to the full capacity online.) In a typical system, the load will change about 1% for each 1% change in frequency as motors and other frequency dependent loads decrease. Taking both of these factors into account, the system frequency will head for a new operating point where the load and generation are balanced at 4988 MW at a frequency of 59.86 Hz. The automatic generation control system will then change the set points of the governors to bring the frequency back to 60.00 Hz.

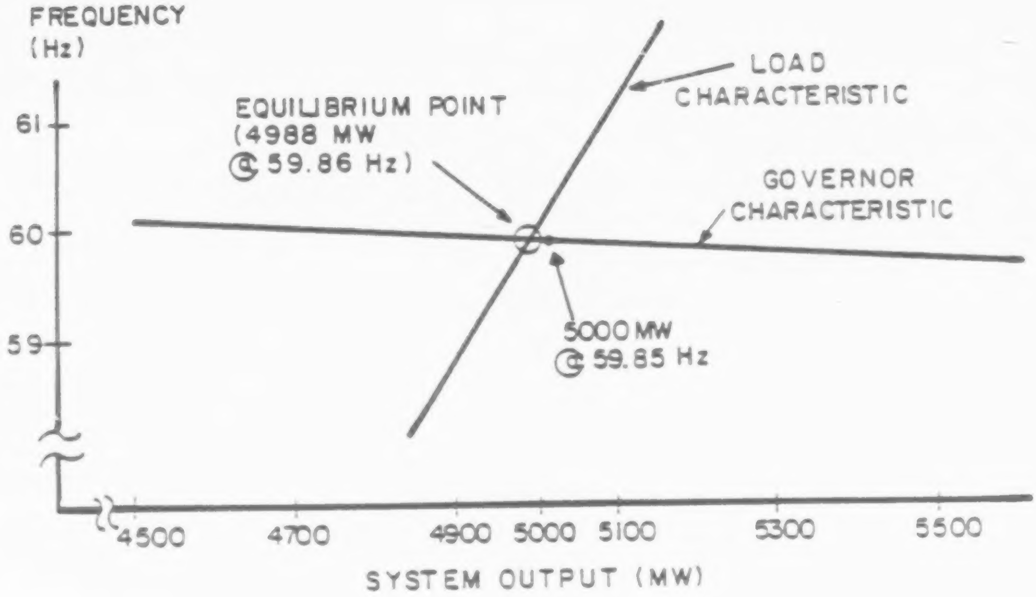


Figure 3.1 - Governor and Load Characteristic for a 300 MW Generation Deficiency

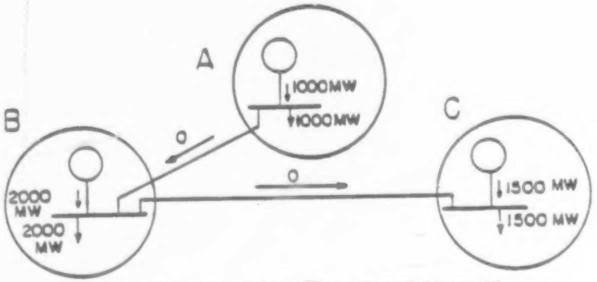
The overall effect on system frequency of these actions (which are taking place all the time as the system load changes from minute to minute) is that the frequency deviates continuously from exactly 60 Hz. On the large Eastern Interconnection the bandwidths observed are about 0.01 to 0.02 Hz on a moment to moment basis with superimposed drifts of longer duration that are about + or - 0.01 Hz.

3.2.1 Automatic Generation Control (AGC)

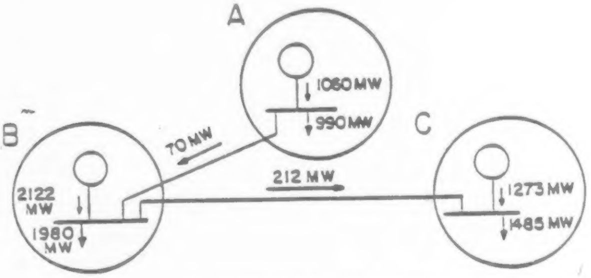
Without further modification to the generation controls, when an interconnected system experienced a momentary generation shortage due to the loss of a unit or a load increase, all of the generators under governor control on an interconnected system would attempt to restore the frequency to normal. (Some units are not on governor control, but are set to produce a fixed power output to minimize the wear stresses on larger units and to minimize power level rates of change on nuclear units.) This would cause a lot of unnecessary control action and would cause the interchanges between systems to deviate from the values that are scheduled as the different units in different systems compete to restore the load-generation balance. Modern automatic generation control (AGC) systems use a tie line bias generation control system where an area control error (ACE) is computed and used as the error signal to reset the governors' set points. The ACE is the sum of the deviation of the actual and scheduled net interchange and a term proportional to the deviation of frequency from 60 Hz. One of the objectives of this type of AGC system is to have the units within a control area respond to normal, internal changes in requirements for generation and not to changes in demand in the external interconnected areas.

The AGC requirements for interconnected system operation may be illustrated by a simple example of three systems operating initially with no scheduled net interchange [26]. Figure 3.2 (a) shows the initial conditions where load and generation are balanced in each area. Next, assume that system C loses a 300 MW unit. The result is shown in Figure 3.2 (b). The frequency begins to drop since the total generation is 300 MW less than the initial, total load of 4500 MW. Governor action in all three areas will increase the generation in all three areas assuming that each system has sufficient capacity online under regulating control.

Figure 3.2 (b) illustrates the effects of the load frequency response and typical governing action after the loss of the generator in system C and before any AGC action has taken place to restore the frequency to exactly 60.0 Hz. The systems are in equilibrium at some frequency below 60 Hz and the deficiency in system C is being made up by power transfers from system A to B and from system B to C. At this point the operators in system C could increase the available generation to pick up their own load again, if there is sufficient operating reserve. But in the mean time there is an unscheduled flow on the interconnections. Without some modification to the governing systems, all three systems would start to restore the frequency to 60 Hz. Modern AGC systems are designed to correct this situation automatically and are designed to determine the generation changes necessary to maintain scheduled net interchange and scheduled frequency.



(a) INITIAL CONDITIONS—NO INTERCHANGE



(b) LOSS OF 300 MW UNIT IN SYSTEM C

Figure 3.2 - Interconnected System Operation

To do so the AGC system must receive sufficient system data to be able to detect both the actual frequency and the actual net interchange that is occurring. Frequency is easy to measure. The net interchange information must be obtained by measuring the power flows at all of the interconnection points of the systems and transmitting these data to the AGC systems in the control centers. The AGC system then calculates what is known as the area control error, or "ACE."

ACE is the sum of two components, the deviation of the actual interchange in MW from the scheduled value and a second term, also in MWs, that represents the deviation of the actual frequency from 60.0 Hz. In mathematical terms:

$$ACE = (ANI - NIS) - (10B) \times (f - 60)$$

where

ANI = actual net interchange, MW

NIS = net interchange scheduled, MW

f = actual frequency, Hz

B = frequency bias term, MW/0.1 Hz
(B is negative. If B = - 100 MW/0.1 Hz,
the system must raise generation 100 MW
for every 0.1 Hz that the frequency drops.)

To see how this works out let us consider the three system examples on Figure 2.6. To do so, several numerical assumptions need to be made. In each area assume that the load frequency response is such that 1% of the load is lost for each 1% drop in frequency and that the governor regulation (i.e., speed droop) is 5%. With these assumptions the frequency will decline by about 0.20 Hz after the 300 MW unit is lost in system C. The interconnecting tie flows shown on Figure 3.2 (b) result. The net interchanges scheduled were all zero.

One more set of numerical assumptions are needed, the values of the frequency bias terms in the AGC systems in each utility control area. Ideally these should be set at a value equal to the sum of the effects of the load-frequency damping plus the regulation. Take system A as an example. The 1% load change for each 1% frequency change, the load damping response, is 10 MW/0.6 Hz or 16.67 MW/Hz. The 5% governor regulation is 1000 MW/3 Hz or 333.33 MW/Hz. Their total is then 350.0 MW/Hz or 35 MW/0.1 Hz. Similar ideal bias terms are assumed in the other two areas. Based on these assumptions we may illustrate the ACE computation as follows. The frequency change prior to the AGC action is -0.20 Hz. Tie flows are taken as positive when flowing out of the system.

AREA	MW Net Interchange Actual - Scheduled	Frequency Bias Term 10(MW/0.1 Hz)(-.2)	Area Control Error (MW)
A	+70 - 0 = 70 MW	- 10(-35)(-.2) = - 70 MW	0
B	212 - 70 - 0 = 142	- 10(-71)(-.2) = - 142	0
C	- 212 - 0 = - 212	- 10(-44)(- 3) = - 88	- 300 MW

These control signals in the three AGC systems cause all of the increase in generation to take place in Area C, the area where the shortage exists. If there is sufficient operating reserve in Area C, the generation in that area can respond. If not, the operators may have to purchase the required amount until standby reserve capacity is brought on line.

The use of the ACE error signal in the AGC system provides a simple way for area generation control systems to discriminate between generation mismatches in their own system as opposed to mismatches in the other interconnected systems. When the ACE is negative the area should increase its own generation; when it is positive it should decrease its generation.

One additional step is required, that of allocating the desired generation change to the generators under control. Three factors enter into this: economics, regulation and assistance. The economic component is a result of economic dispatch computations and is a control signal to each unit that is based on the desired economic participation of the unit in the total load change called for. The regulating component is designed to allocate more of the desired change to those units that can respond best when generation adjustments are required to meet expected changes in demand. The assist component is designed so that those units that can, will provide the needed generation changes when a large total change is required.

These AGC systems work quite well and do so largely due to the small frequency deviations that occur [34]. This is a strong reason to maintain frequency performance standards (e.g., that could be disturbed by any potential industry restructuring.) Another factor that contributes to the success of the interconnection operations is the cooperation of the utility system operators in self-policing and in establishing voluntary working arrangements amongst themselves [25]. The establishment of agreements concerning the required operating and standby reserve levels is quite important in the reduction of inadvertent interchange in the interconnected systems. The introduction of non-utility generation into the systems generally may increase reserve requirements if the non-utility resources cannot be classified as firm supplies.

3.2.2 Transient Operating Phenomena

When a generating unit does fail suddenly and has to be taken off line, the other units require time before their governors act to increase the units' outputs. In the meantime, the system will receive power over the transmission lines which interconnect it with other power systems as all of the synchronously interconnected system slows down to achieve a balance between load and generation. Transiently, the load-generation balance is achieved by power being extracted from the collective kinetic energy stored in the rotating masses in the generators plus the decrease in load that take place as the frequency drops. In the steady state , and assuming that the controls did not act to restore the frequency, there would be a stable balance between the load and generation at some frequency less than 60 Hz because of the speed droop governing characteristic and because power system loads drop off as the frequency is reduced. This "load damping" effect makes a positive contribution to the action of the generation control systems used. In practice, the sudden removal of a large generation source from an interconnected system results in a transient drop in the frequency that is eliminated within minutes as the AGC systems come into action and increase the outputs of all of the units under control.

Faults on the transmission systems or in a substation generally have the opposite effect to that caused by the sudden loss of generation. Suppose a high voltage circuit is struck by lightning and is short circuited to ground. This short circuit permits the currents flowing on the line to travel directly to ground without flowing through the load. The short circuit changes the electrical characteristics of the network and tends to reduce the voltage at the point where the loads are served. The overall effect is a sudden reduction of the load that is being served by the generation system. In this case the system tends to speed up and would continue to do so without some further action. In the case of faults (i.e., short circuits) the action that takes place is quite rapid (e.g., cycles to seconds) when compared with the governor response of the generators (i.e., minutes.) Usually a fault will be cleared within a few cycles of its initiation by the combined action of the protective relaying system and the interruption of the fault by the opening of high voltage circuit breakers. This action increases the load imposed on the generation, causing it to slow down. This is a transient phenomena with no built-in guarantee that the system will return to a condition of stable operation. If the system has accelerated too much, synchronism may be lost and the different generators on the system will pull out of step. If there is sufficient damping in the system, synchronism will not be lost and the system will resume normal operation. This is known as the "transient stability problem" by power engineers and is one which has long plagued systems with long lines and remotely located generation.

The systems are designed to survive these short circuits and transient stability problems by examining the expected behavior of the system using computer models and postulating various events that can result in the type of system behavior just described. The ability of the system to survive this type of fault is a function of the capacity and electrical parameters of the transmission system. System operators keep some transmission capacity in reserve using contingency constrained scheduling measures in order to prevent widespread system outages. It is quite possible that a fault that results in the removal of a particular circuit or line section may result in the subsequent overloading of other circuits as the system loading pattern adjusts automatically. Overloaded circuits are removed from service automatically by the actions of protective devices to prevent severe damage to lines and transformers. Without proper design and operation, the occurrence of a single fault could result in the cascading of outages and a widespread system blackout. Several major blackouts have resulted since 1965 from just this type of circumstance. The consequence is that today, most system operators will operate the system in a "defensive mode" where no "credible" failure event will cause a cascading sequence of outages. This, probably more than any other factor except the physical limitations of the circuit, limits the loading of transmission circuits.

3.3 VOLTAGE CONTROL

Voltages on the interconnected systems must be controlled to protect the equipment on the system and keep the voltage magnitudes within control range limits. If the voltage level gets too far out of range due to heavy transmission flows, outages, or circuits, the voltage control devices in the distribution system may not be able to bring them to back to the proper utilization levels. The requirement to control the voltage magnitudes means that the supply of VARs on the system must be engineered properly and that the system operators must keep voltages within tolerable limits at the various electrical busses in the system. When voltage gradients in the system exceed normal ranges, it indicates that VARs are being transmitted from remote locations and that the system's losses are probably too high. Supplying VARs as close as possible to the points where they are needed for voltage control is a common practice to avoid transmitting VARs and reduce system losses. Voltages are controlled independently (i.e., they are not controlled as a part of AGC functions.)

Voltages are automatically established at the generators by controlling the generator field excitation levels with voltage regulators. (Magnetic fields are established in generators to generate voltages in the windings connected to the power system by current flowing through the field windings. This is referred to as field excitation.) Voltage changes in the system itself are primarily a result of the flow of VARs through various circuit elements, the generation and absorbing of VARs in the system, and the effects of various voltage regulating and control equipment. Some of these changes occur naturally as a consequence of the VAR and power flows while others are a result of control actions that take place automatically or are initiated by system operators.

VARs may be supplied (or absorbed) by several means within the control of the system operators and by automatic voltage control devices in the system.

Generators can supply or absorb VARs as well as producing real power. Figure 3.3 illustrates typical capability limitations of a generator. The curve shows the allowable operating regime of a typical machine in terms of the power being generated (the MWs) and the millions of VARs (MVAR) being generated or absorbed by the unit. Power output is controlled by controlling the input to the prime mover and the VARs are controlled by the excitation system that controls the voltage at the generator's terminals.

The limitations shown on this curve are the result of several physical constraints. When the unit is supplying VARs to the system (the overexcitation region on the figure) the maximum output is limited by the temperature rise caused by the heating effects of the currents flowing in the armature winding or the field windings of the unit. When the unit is absorbing VARs (the underexcitation region on the curve) the limitations are due to heating effects of the current in the armature winding and the heating of the materials in the end regions of the generator due to the electromagnetic fields. Limits in this region may also be imposed by dynamic stability problems associated with system operation.

Synchronous condensers are rotating machines that are also used to generate or absorb VARs. These are machines, similar to generators except that they do not generate real power, only VARs. The level of VAR generation or absorption is automatically controlled by the excitation system and may be accomplished automatically in order to hold the voltage magnitude at some point in the system.

Transformers are used throughout the power system to change voltage levels when going from one subsystem to another. These transformers may have automatic or manually controlled tap changing devices incorporated in them so that voltages are transformed with an incremental voltage magnitude change superimposed on the nominal voltage transformation. For example a transformer in a distribution substation might be used to reduce the transmission voltage of 138 kV down to a level of 34.5 kV for the primary system.

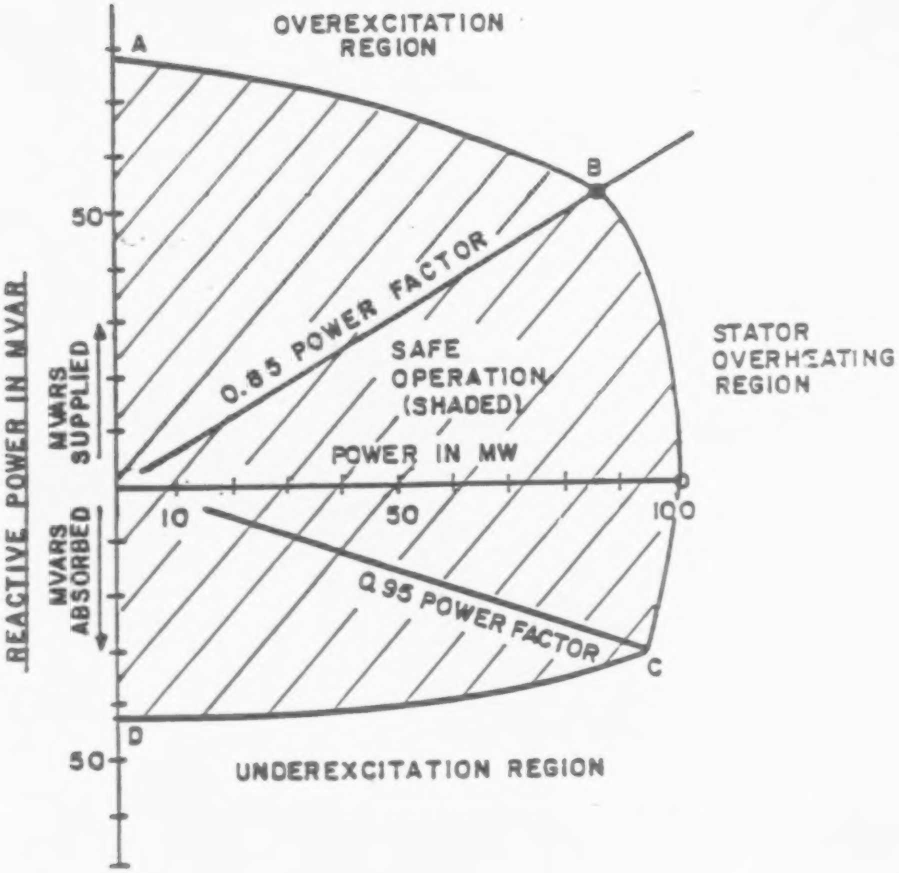


Figure 3.3 - Generator Capability Curve

The transformer might have adjustable taps that allow a variation of 5% up or down in the output voltage. The tap changer that accomplishes this may be under automatic or manual control depending on the particular transformer design. Some transformers incorporate automatic tap changers while others do not. Using this type of device, voltages may be adjusted at various stations in the network.

Capacitors, shunt reactors and static VAR supplies may be installed at various stations to absorb and/or generate VARs to affect voltage control. These devices may be controlled by switching them in and out of the network, or in the case of the static VAR sources, it may be done by automatic control devices. The various types of voltage control devices are installed in transmission, subtransmission, and distribution systems.

System planners and operators establish a range of allowable voltage levels at various points in the system both for normal and emergency conditions. Since voltage control involves the flow of VARs in the network, the system's real power losses are affected. There are some newer analytical techniques (e.g., optimal load flow programs) in use for scheduling voltages and VARs that minimize the real power losses in the network.

3.4 SECURITY DISPATCH OF GENERATION

The basis for the security constrained dispatch of power generation is the scheduling of generation in a defensive mode so that a "worst case" contingency will not result in an overloaded circuit or a voltage out of range on the system. The worst case contingency may be a single outage event in some systems while others use double contingencies to search for the worst case.

The methods used in control centers are based on load flow calculations of network flows and voltages [33, 37, 38]. The dispatchers (or the software system itself) will run a series of contingency cases and compute the generation shifts required to prevent circuit overloads or out of range voltages. The generation shifts are displacements from the optimal economic dispatch and may be based on minimizing the control action required or on minimizing the operating cost penalty. Power system engineers have developed sophisticated mathematical models that enable them to find worst case events rapidly and to determine what generation shifting needs to take place.

The purpose is to prevent the occurrence of cascading outages that are started when a single contingency, (e.g., a major transmission line outage) causes the subsequent overloading of additional circuits. The use of security constrained generation scheduling practices is widespread and appears to have reduced the incidence of major blackouts. These events are so rare that reliable statistical data are not available.

An important consequence of this operating practice is that transmission capability is normally held in reserve for the possible occurrence of a major failure in the system. Another, and important consequence for any discussion of transmission access by non-utility entities, is that available transmission capability, itself, is a function of the security dispatch practices and analyses used. The available transmission capacity is a function not only of the physical parameters of the circuit elements, but also the loading of the network.

Thus the transfer capability between interconnected systems will depend on the flows between these systems and other interconnected systems [39 - 40]. Within a single system the transmission limits will depend on the load level, the distribution of load and generation, and transfers taking place between the system and its interconnected neighbors.

The concept of transfer capability has become very important in evaluating the adequacy of the interconnections between systems. Transfer capability is a measure in MWs of the capacity of a transmission network to allow reliable transfer of power from one area to another. The areas involved could be different parts of the same system, different utilities or power pools. "Reliable" implies that such transfers should not cause the overall system performance to violate established criteria under certain contingencies.

Transfer capability is the ability to transfer power, and therefore it is a function of the strength of the transmission network. Its numerical value depends on the contingencies that the system must withstand. Transfer capability is affected by the transmission system configuration, applicable transmission line ratings, reactive power support, system load level and distribution, and generation locations and dispatch.

The NERC publication, "Transfer Capability: A Reference Document," contains definitions of different types of transfer capability, simulation techniques to estimate transfer capability, and guidelines for establishing transfer capability objectives [39]. NERC defines transfer capability as "incremental" or "total." "Incremental" refers to capability above the normal base power transfers and is a measure of the ability of the transmission network to cope with emergency conditions with all normal power flows considered. "Total" transfer capability is based on both normal base power flows and incremental flows and represents the total amount of power that can be transferred between two areas. It is more convenient to use total transfer capability throughout these discussions.

Definitions are also given in this reference for the contingencies used in calculating transfer capability. The most common convention, "First Contingency Incremental Transfer Capability (FCITC)," is the amount of power (incremental above normal base power transfers) that can be transferred over the transmission network in a reliable manner, based on the following conditions:

"1. With all transmission facilities in service, all facility loadings are within normal ratings and all voltages are within normal limits.

2. The bulk power system is capable of absorbing the dynamic power swings and remaining stable following a disturbance resulting in the loss of any single generating unit, transmission circuit or transformer.

3. After the dynamic power swings following a disturbance resulting in the loss of any single generating unit, transmission circuit or transformer, but before operator-directed system adjustments are made, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits."

"Second Contingency Incremental Transfer Capability" is defined similarly but considers sequential and overlapping outages of two facilities.

For systems with interconnections involving more than two areas, effects of simultaneous transfers must be recognized. The simultaneous transfer capability from several areas to an area is different from (generally less than) the sum of the non-simultaneous transfer capabilities from the individual areas to this area. The direction of transfer is also recognized as from "area X to area Y" versus "area Y to area X," or "simultaneous imports of area X" versus "simultaneous exports of area X."

In multi-area context, transfer capability between any two areas depends on transfers between other pairs of areas. Some systems show transfer capability relationships with bi-axis polygons like that of Figure 3.4. For example, the Y to X transfer capability is 6200 MW when X to Z transfer is 5200 MW. The Z to X transfer capability is 2600 MW when X to Y transfer is 1300 MW. The simultaneous maximum net import capability of X is 4350 MW (not 6200 + 2600 MW), which occurs when there are no transfers between X and Z. Two additional bi-axis polygons are required, showing imports/exports of Y and Z, for a complete description of the three-area system.

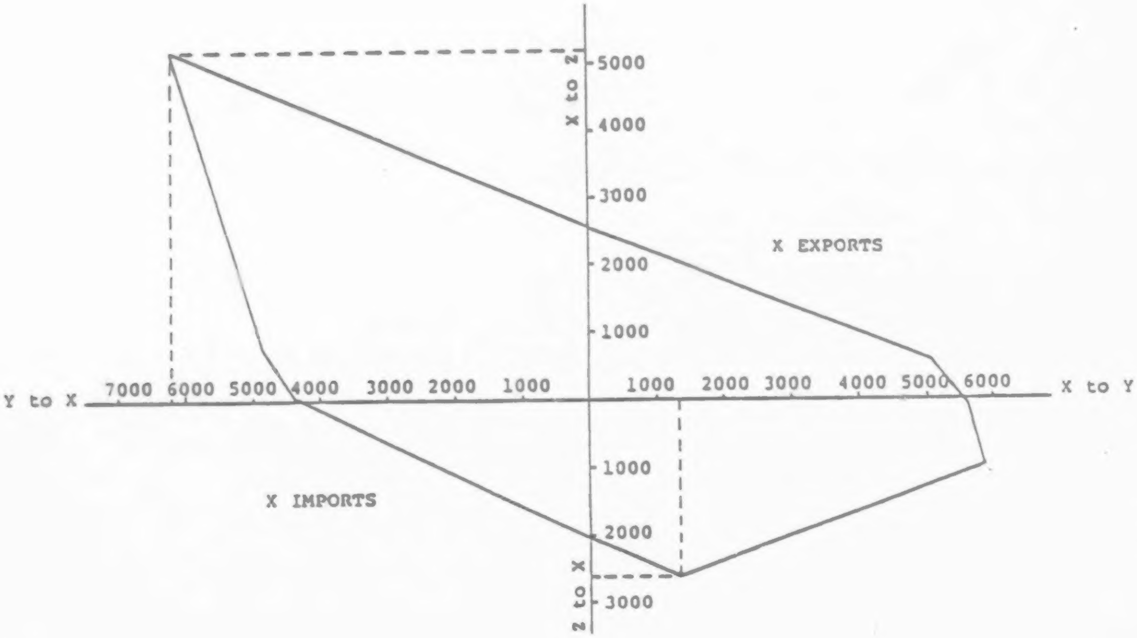


Figure 3.4 - Typical Bi-Axis Transfer Capability Polygon [40]

The analysis used to determine transfer capability is based on ac load flow methods, or dc load flow simulations if adequate. Computer programs are sometimes used to determine dependent inter-area transfer capabilities suitable for representation by a polygon. Two such programs are TLIM (Transmission Limitations), used in the Pennsylvania-New Jersey-Maryland Interconnection (PJM) power pool, and SLANT (System Linear Analysis Technique), used in the Mid-America Interpool Network (MAIN) and Mid-Continent Area Power Pool (MAPP) [40].

CHAPTER IV

CHAPTER 4

LIMITATIONS TO TRANSMISSION SYSTEMS

4.1 GENERAL COMMENTS

Transmission systems serve at least four basic functions in the electric power system.

1. They transmit electric power from the generation sources to the load and permit the integrated operation of utility systems.
2. They provide a means of sharing generation reserves amongst interconnected systems.
3. They allow the interchange of power and energy amongst interconnected systems on both short and long term basis.
4. They provide transmission service to cogenerators and other non-utility generation sources to deliver energy to the system and its customers.

The limitations to the loading of transmission systems in the U.S. are due to only a few fundamental factors. These are:

- the thermal capacity of the transmission circuits and associated substation equipment, breakers, transformers and station busses,
- the voltage limits that must be held in order to achieve safe system operation, and
- the system operating related problems that must be solved in order to insure economic, secure and reliable system performance, including the establishment of adequate transmission reserve requirements and the avoidance of dynamic operating problems that may cause system disruption.

Financial limitations and environmental concerns may preclude or retard the installations of new transmission facilities.

Transmission systems were designed primarily to meet the requirements imposed by the first function, the connection of generating plants to load centers, but the needs in the last three areas have grown steadily in the last 25 years. In that period the number of interchange and wheeling transactions has grown two to four times as rapidly as the sales to ultimate consumers. In more recent years the rapid changes in the relative prices of fuel, the adoption of environmental regulations that have limited the placement of new generating plants, and the growth of interchange transactions has greatly accelerated. All of these changes have imposed new requirements on the transmission systems at the same time that financial and environmental concerns have decelerated the growth in the transmission system.

Load growth rates have fallen, nuclear construction programs have been delayed or dropped, fuel prices have changed dramatically, and non-utility generation sources have arisen as a possible major source of supply. At the same time the construction of new major high voltage lines has become more difficult. Line construction projects planned for normal completion in 2 or 3 years have taken up to 10 years to complete in areas where strong environmentally based opposition has arisen [20].

Line configurations, that is, voltage levels and number of circuits and their locations on the network, are established by utility planning engineers to accommodate the expected installation of new generation, the expected load growth and the need for system integration and interconnection. Because power flows are only indirectly controllable on ac circuits, planning engineers must consider the possible consequences of outages of major system components. When one of a number of parallel circuits is opened, say due to a short circuit, the power flows on the adjacent lines in the system will instantly be forced to carry increased flows as the power originally flowing on the removed line redistributes automatically to satisfy the laws of physics. This means that planning engineers must plan on some level of redundancy in the network and that system operators must operate the system with transmission capacity in reserve to allow for system failures. Without these reserve margins, systems would more than likely suffer many more blackouts due to cascading failures initiated by single outage events.

The growth of the interconnected networks has complicated transmission system planning and operation since power flows do not respect ownership boundaries. System operators must be aware of the operations in adjacent interconnected systems at all times and coordinate their own operations with those of neighboring systems to the extent that they avoid mutual interference with each other. Electric power transmission systems are different from other types of transportation networks where flows can be controlled and capacities used to maximize the flow through the network. In a power system the transmission capacity that is available changes with time and with the particular operating reliability criteria used in operating the system. This, of course, complicates the answer to the question of what transmission capacity is available for additional power flows.

Lines are designed to have large enough conductors to carry the anticipated loads considering the effects of conductor size and configuration on the expected losses in the circuit and the impedance offered to the flow of power. "Impedance" in an electric circuit is like friction in a pipe or bottlenecks on a highway that reduces the flow. The concept is a little more complicated because electrical circuit impedance is due to energy dissipation and changes in the energy stored in the electric and magnetic fields accompanying the flow of current in a conductor.

Voltage levels of the transmission system are selected on the basis of the expected capacity requirements, balancing the economic considerations with design reliability criteria. The result is that a given voltage level transmission line may carry quite different loadings in different systems and at different times in the same system as load and generation patterns change.

Many, if not most, transmission systems are limited by more than one factor. As systems have evolved over time they may have grown out of one type of limitation into another. The eastern interconnected systems are one example where external conditions have served to alter the nature of the limitation as the level of imported power from Canadian sources has grown.

Transmission capability limitations affect system planning and operations in various ways according to the function intended. For example, limited capability on interconnections between systems may:

- reduce the ability to engage in economy interchange and wheeling transactions, and
- reduce the ability of the systems to share installed generation reserves thus increasing reserve requirements for the same reliability level.

Transmission limitations within a single system may restrict the system's ability to implement optimal economic generation schedules since generation schedules will have to be altered to prevent circuit overloads.

The material in this report related to transmission limits and remedies is based in large measure upon the Final Report on EPRI Project 5005-2, "Technical Limitations To Transmission System Operations", prepared by Power Technologies, Inc. and submitted to EPRI in August, 1987 [42]. One of the goals of the EPRI project was to cite areas where increased research and development efforts are needed to relieve some of the limitations. That is only subsidiary to this current report and more emphasis is placed in this and the next chapters on currently available means for relieving some of these limitations.

4.2 TRANSMISSION LINE LIMITATIONS

Transmission circuit limitations are related to the physical characteristics of the network elements (i.e., the current carrying capacities and design voltages of the lines, cables, transformers, breakers, etc.) and the parameters that describe the network performance (i.e., the system voltage levels and values, currents, and VARs flowing, etc.) These characteristics and parameters are interrelated in that the values of the characteristics effectively act as constraints on the network parameters. These characteristics and parameters include:

- the reactances of the circuit elements,

- the thermal capacity of the circuit elements,
- the voltages characteristics of the network elements and the voltages that occur in the network, and
- the current carrying capacity of circuit elements (which are essentially determined by their thermal capacities) and the currents actually flowing in the network.

4.2.1 Reactance

In a transmission line the flow of current is opposed by the impedance of the line. This is mostly due to the changing energy storage in the magnetic fields surrounding the conductors and is called reactance (more properly the inductive reactance.) The magnitude of the inductive reactance is a function of the geometry of the conductors, their spacings from each other, and above ground plane. The reactance is designated by the symbol "X." Reactance is extremely important to power transfer transmission line limits. This reactance is a major factor in the creation of two fundamental limits, voltage drop along the conductor and the stability of the system. The voltage drop along the line is almost directly proportional to the reactance.

Steady state stability limits the maximum power that can be transmitted over any transmission line to a level inversely proportional to its reactance. This limit appears in the classical power-angle relationship for ac power transfer over a single transmission line [40].

POWER ANGLE EQUATION

This report contains very few equations, but the power-angle relationship is so fundamental to understanding some of the limitations to electric power transmission that an exception was felt to be warranted.

In an ac circuit the voltages and currents vary with time, oscillating at 60 Hz per second. A picture would show these oscillations to be sinusoidal. The sinusoidal oscillations of the various voltages and currents are generally displaced from each other. That is, the maximum value of the various voltages and currents occur at different times. These time differences may be converted to fractions of a cycle, or degrees for a constant frequency and are referred to as phase angle differences. When the phase angle difference between two quantities is zero they are said to be "in phase" or "in time phase" with each other. Voltages in various parts of an ac circuit are not necessarily in a time phase with each other nor is the current through any element necessarily be in phase with the voltage.

Engineers and scientists have long represented these sinusoidally varying voltages and currents by rotating vectors, called "phasors" in modern terminology. The analysis of electric power circuit performance is greatly simplified mathematically if these phasors are viewed from a reference frame that is rotating at 60 Hz per second so the voltage and current phasors are fixed when the circuit is in the steady state.

On each end of a transmission line the voltage phasor may be measured with respect to the zero voltage of the ground. Each voltage will be characterized by a magnitude (V_1 and V_2) and angle with respect to the reference frame. On a transmission line the difference between the angles of the two terminal voltage phasors is usually designated by the Greek letter "delta" (δ) and is called the "phase angle" or "electrical angle".

The fundamental equation that relates the power flow over a line as a function of the voltage magnitudes at the two ends, the line's reactance and the phase angle between the voltages at the two ends is called the "power angle equation."

$$P = \frac{V_1 \times V_2 \sin(\delta)}{X}$$

where P = the power transfer,
V_1 = the sending end voltage magnitude,
V_2 = the receiving end voltage magnitude,
X = the total reactance between V_1 and V_2, and
δ = the power angle between V_1 and V_2.

The power angle equation shows that the power flow over a line may be increased by:

- increasing the voltage magnitudes,
- decreasing the line's reactance, and
- increasing the phase angle difference.

By increasing the voltages at the two ends of the line together, the power transmitted increases by the square of the voltage. By increasing the current and keeping the reactance constant, the power angle increases toward its theoretical maximum of 90 degrees. At the same time the voltage drop along the line increases so that in practice this angle cannot be nearly that large and is usually limited to 30 degrees for practical operating conditions.

Voltages may be increased only to the point where they do not exceed the ratings of the equipment and line insulation strength. This is usually about 5 to 6% over the line's rating. Beyond that point the line and equipment may have to be changed to allow the voltage to increase further.

Line reactance may be changed by reconductoring the circuit. A line with two or more conductors per phase, a "bundled conductor", has less reactance per mile than one with a single conductor per phase [18]. Series capacitors may be inserted into the line and will cancel out some of the inductive reactance of the line. (Reactance comes in two types, inductive due to energy storage in magnetic fields and capacitive caused by energy storage in electric fields. Capacitive reactance is due to changing energy storage in electric fields between two conductors or between a conductor and ground It also may act as an impedance to the flow of current in an ac circuit. Capacitive reactance and inductive reactance have opposite signs in circuit equations.)

The power angle equation also shows that the phase angle between the voltages will increase as the power flow increases, but only up to a theoretical maximum of 90 degrees. Beyond that angle the sine of the angle decreases, decreasing the power flow. The angular difference is caused by the voltage drop along the line in the direction of the power flow. This in turn is directly proportional to the reactance of the line so that reducing the line reactance reduces the phase angle for a given power flow.

4.2.2 Thermal

Another fundamental physical limitation to the loading of an overhead transmission line or other circuit element is the thermal limitation [43]. The real power losses (MW) in a transmission line (or other circuit element) are due to the resistance of the line. This causes power to be dissipated in the form of heat as current flows through the line. Generally for modern high voltage overhead transmission lines the ratio of reactance to resistance is in the order of 10 to 1. Current flowing through lines also causes reactive power losses (VARs) due to the line's inductive reactance.

The flow of current causes MW losses in a transmission line which will increase its temperature. If the temperature rise is too great, an overhead line will sag and may take a permanent set or even sag so far that it touches the ground or a structure under the line. The allowable temperature rise is determined by the conductor materials and by local weather conditions (wind velocity, temperature etc.) Static thermal limits are usually calculated assuming standard conditions allow safety margins. The result is that lines only rarely fail from excessive sag.

Underground cables and power transformers are much more frequently (if not always) limited by thermal considerations. The cables, being buried under the earth, depend upon the cable cooling system (if any) and the heat dissipation characteristics of the surrounding soil [22, 24]. Operating these underground cables at excess temperatures will shorten their service lives considerably due to damage to the insulating medium. Mechanical problems due to heating are usually not a limitation.

Power transformers are designed to operate at a maximum temperature rise to protect insulating mediums also. Capabilities may be increased by designing transformers with forced cooling.

4.2.3 Voltage

Voltage limitations on transmission circuits are primarily associated with safety standards and the need to prevent line flashovers due to transients caused by lightning strokes or switching on the system. Line insulators support overhead conductors and must keep them separated mechanically from each other and from the tower structure. Clearances are established by the National Electric Safety Code Clearance Requirements for the various voltage classes. Circuits designed and constructed for one voltage class can occasionally be upgraded to a higher voltage class to increase the transmission capability, but usually only after a careful study of all of the factors involved. Circuits that are to be increased in voltage usually require a rebuilding of the towers.

Low voltage limitations result from operating considerations. Voltages must be kept within ranges that allow voltage correcting apparatus (e.g., tap changing transformers) to maintain customer voltages within tolerances.

4.2.4 Current

Uprating a transmission line by increasing its current carrying capacity may be a more practical way to increase line capacity than increasing the line voltage. One method may be to increase the allowable temperature rise and base the time-temperature limits on more liberal criteria. Another technique is to use dynamic line ratings that rely on measurements of line sag, temperature and local weather conditions to permit the line to operate closer to its physical limits for short periods during emergencies [44 - 46].

Higher line currents in an overhead line will probably require that the line be restrung (i.e., resagged) to preserve the required midspan clearances. This can be done in some cases (and has been) while the line is still in service [47].

Another feasible technique for increasing the current carrying capability is to reconductor the line with a larger conductor or replace a single conductor per phase arrangement with a bundle of two (or more) conductors [18, 46 - 48]. This procedure usually requires the mechanical reinforcement of the existing tower structures. The Duke Power Company is one of the major U.S. utilities that has reported, during the survey done as part of the EPRI project referred to previously, that this is a very economical procedure, costing about 40% of new line construction.

With the increasing difficulty of obtaining new rights-of-way, one alternative to increase the transmission capability of a corridor is to completely rebuild the circuits either with existing towers or with new construction. Newer line design methods coupled with reduced clearance requirements may permit the construction of a compact line of higher voltage or the expansion of a single circuit line to a compact double circuit tower line.

One newer proposal is to make use of 6 or 12 phase construction rather than the conventional 3 phase line construction to increase the line capability. This has been explored extensively in theory and in demonstration projects, but has not as yet been applied to a major line reconstruction [51 - 53].

Another proposed technique for increasing the capacity of a transmission line is to convert a high voltage ac line to dc. This has been proposed, but not tried as yet [54 - 56]. It would theoretically allow an increase in capability with the same voltage levels with respect to ground. It would eliminate the problems with stability and voltage drop caused by the line reactance.

Existing underground cable systems may be uprated by operating the line closer to its thermal capacity or increasing the cooling available by treating the soil surrounding the cable with material which transmits heat efficiently. Increasing the cooling of the conductors may augment cable ratings using forced cooling in place of self-cooling by installing cooling oil circulating pumps for example [57-59].

4.3 LIMITATIONS IN SUBSTATION EQUIPMENT

Substation equipment limitations are due to current (i.e., thermal) and voltage limits. The equipment in major substations includes bus work, transformers, switches, relaying and protective systems and power circuit breakers. These are designed for the voltage levels and current carrying requirements of the station. Their loading limitations are due primarily to the thermal capability of the equipment. Increasing these may be possible by applying forced cooling techniques to transformers and buses. Circuit breaker and switch thermal limits are seldom limiting in a substation [60 - 64].

When non-utility generation is added to a system or various means are used to increase the circuit capabilities of the transmission network, the short circuit duties imposed on the breakers must be carefully checked to make certain that they are not exceeded. The breakers installed were selected to interrupt fault currents (i.e., their short circuit duty) based upon the expected configuration of utility installed generation and circuit impedances. The subsequent introduction of additional generators may increase the breaker interrupting duty beyond the breaker capability, requiring replacement or modification of circuits to reduce the fault current.

Generally if a transmission circuit is going to be uprated by increasing its current carrying capacity or voltage level, the equipment in the associated substations must be replaced to accommodate the increased currents or voltage levels. The higher capacity, higher voltage replacements may not fit the available space in the station. This may be a problem in stations where space is limited.

4.4 LIMITS RELATED TO SYSTEM PERFORMANCE AND OPERATION

A number of transmission limitations that are related to system operation and performance include; (1) power flow distributions, (2) voltage-VAR related problems, (3) system dynamic problems (stability, plant response etc) and (4) system operating limitations that result (or are imposed) because of concerns with system operating security and reliability.

The largest group of limitations to the effective transmission capacity is that related to reliable system performance and operations. The electric power network is a complex system containing many interacting electrical and mechanical subsystems. Power flows on an electrical network must flow in patterns that satisfy the physical laws governing the behavior of electrical systems. This results in more complex patterns than those found in transportation networks where flows can be directed, stored and limited to make use of maximum transfer capacities of the various links in the system. For example, the flows of goods over a highway network via truck fleets may be scheduled in such a fashion that shipping costs are minimized while making maximum use of available network and truck fleets. If one route becomes congested, trucks may be dispatched over alternate routes or shipments delayed en route to allow the congestion to subside. The same is true for airlines, trains, and gas pipelines where gas may be stored in reservoirs or even in the pipeline itself. In an electrical system the product, electrical energy, must be delivered at essentially the same instant it is produced and the flow patterns in the ac network adjust instantaneously and automatically to satisfy the physical laws governing their behavior. Perhaps the future will see the development of a practical and economic electrical energy storage system using superconductive electromagnetic storage, but for the foreseeable future, electrical energy must be used the moment it is produced.

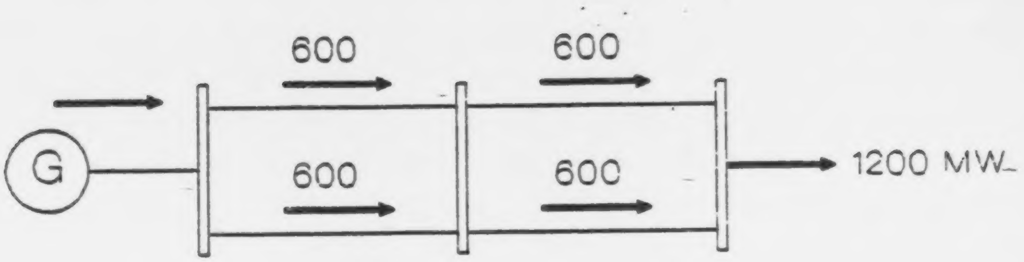
The transportation system for electric energy is the transmission network. Power flows in ac systems will redirect themselves if the circuit configuration changes, the load changes or the pattern of generation is changed. These factors make the scheduling of the power system quite complex and further complicate the definition of "available transmission capacity."

The previous section dealt primarily with the physical characteristics of various circuit elements and the limits these inherent characteristics impose on the transmission system. The consequences of violating the various limitations are different and depend upon the particular violation. Exceeding thermal limitations may cause severe physical damage to the system components such as causing an overhead line to sag excessively and may result in equipment failures that isolate stations or areas of the system or even cause blackouts. Exceeding voltage limits can cause equipment failures where voltages are too high or system collapse if the voltages get too low. A temporary excess of generation will cause the frequency to increase and, if prolonged, will result in the shutdown of the system due to the action of protective systems that will shut down the steam turbine generators to protect them from the consequences of overspeed conditions. (Modern steam turbines and generators have only a very limited overspeed capability.) A shortage of generation will cause underfrequency operation that will result in the operation of automatic load shedding protective systems that attempt to regain the balance between generation and load. A prolonged generation shortage may cause system operators to impose rolling blackouts, where portions of the load are deliberately dropped for a time in order to keep the system operating.

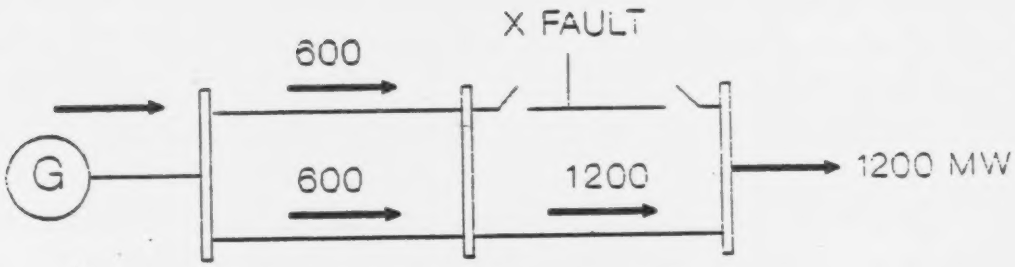
4.4.1 Power Flow Distribution - Effects of Circuit Outages

The load division between the circuits on a transmission system instantly adjusts automatically to satisfy the laws of physics governing electrical networks. This results in the restriction of power flows on transmission systems because of the need to operate the system with adequate safety margins.

Consider the parallel ac network shown on Figure 4.1 [42]. This simple system has two parallel 345 kV circuits that are capable of transmitting 1000 MW each without exceeding thermal limits. The lines are connected in parallel at the ends and in the middle of the circuits. Suppose the system operators wished to schedule 1200 MW over these two lines. Assuming similar electrical characteristics in each line, the load would divide equally with 600 MW on each circuit. This is well within the loading limitations of the circuits.



(A) Initial Line Loading



(B) Loading After Faulted Section Removed

Figure 4.1 - Parallel 345 kV Circuits.
Line loading Increases when faulted section is removed.

Next suppose that the second section of one of the circuits was subjected to a fault and was removed automatically from service by the combined actions of the protective relaying system and the circuit breakers at each end of the faulted line. The new power flow distribution would be approximately as shown on Figure 4.1 (B) with the circuit paralleling the removed line section now carrying 1200 MW, a loading 20% in excess of its rating. This loading would not be allowed for a prolonged period, and the second circuit would be opened automatically by the protective system.

The system operators could take two conceivable courses to prevent damages to the network. One would be to attempt to redistribute the power flows, initiating generation or switching changes rapidly enough after the fault to prevent serious damage. This is difficult to achieve in an ac network, however, since power flows cannot be directed like the flow of water through a pipe. Controls that are available are limited to shifting generation, switching the circuits to attempt to redirect flows, and curtailing loads to reduce power flows.

A more reliable and secure operating procedure is to limit the initial power flows so that after the occurrence of a fault, the flows are still within the limits of the circuits without requiring further operator action. In this case the initial flow would have to be limited to 1000 MW so that after the fault and line section removal, the remaining section would be carrying no more than 1000 MW on a single circuit. This means that the effective transmission capacity on each circuit is limited to 500 MW.

The situation in actual transmission networks is more complicated, of course. The circuit configurations are much more complex and the redistribution of power flows after a fault or line removal are more complicated. Nevertheless, the ideas in operating a system securely are similar. In the example above, if the circuits were carrying 1200 MW and the line section was removed, the protective systems on the remaining section would have removed the second circuit to prevent damage to the circuit elements. The result would have been the complete loss of the transmission path and redistribution of the 1200 MW on other parallel circuits quite probably resulting in additional circuit overloads and subsequent removal. This is a an illustration of a cascading failure. This type of cascading failure has caused system blackouts and is one of the major concerns of system operators.

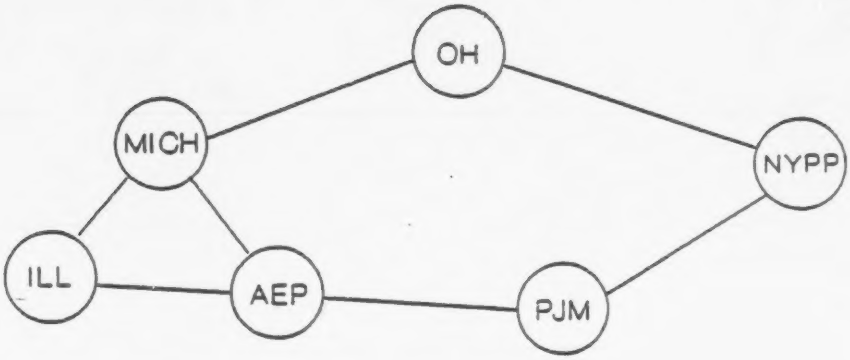
The prevention of these types of possible events seems simple in principle; just operate the system at loading levels that will not result in severe overloads or low voltages in case of failures. However, it requires the establishment of operating guidelines and practices that balance the concerns over system security with the economics of system design and operation. This technique is incorporated in the security constrained dispatch methods discussed in the previous chapter and used to prevent widespread blackouts. A key element in the use of this practice is the adoption of a set of guidelines to define what possible contingencies are to be considered in developing a secure system schedule. Once this is done, analytical techniques are available which allow system operators and planning engineers to develop defensive scheduling methods to minimize the possibilities of cascading failures.

4.4.2 Loop Flows

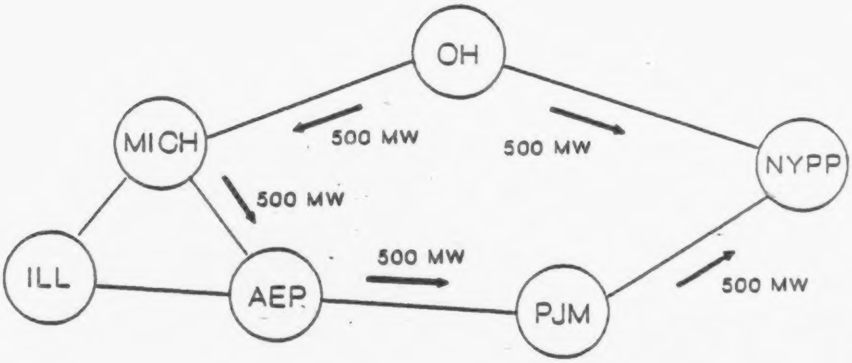
Another consequence of the inherent inability to direct ac power flows in a simple fashion is the "loop flow" that occurs when power interchanges are scheduled on the interconnected systems. In a tightly interconnected system such as that found in the eastern and western parts of the U.S. and Canadian systems these loop flows will take place through a large number of intervening and adjacent systems. Further complications are caused by the fact that a number of transactions usually are taking place simultaneously. The effects of these simultaneous transactions are additive in the flows over some circuits, increasing the power flows on some transmission circuits. In other circuits the flows due to two simultaneous interchanges and consequent loop flows may be in opposite directions and actually reduce the total power flowing over a specific set of circuits.

Figures 4.2 and 4.3 contain a very simplified example of loop flows in the Eastern Interconnection using hypothetical examples [65]. The six systems shown are those in Ontario (OH), New York (NYPP), PJM, the American Electric Power system (AEP) in the midwest, the systems in Illinois and those in Michigan. Several intervening and adjacent systems are omitted that would actually be involved in the loop flow example below.

For purposes of illustration assume that OH is to deliver 1000 MW to the NYPP systems. Figure 4.2 (B) shows the approximate paths that this interchange will follow. Only about 500 MW will flow over the direct, contract path between the two parties involved. The other 500 MW will flow largely through the path between OH and AEP then east and north through the PJM systems to New York. Actually in a case like this some power would flow through northern Ohio to New York and some would flow in the systems south and east of AEP in the Virginias and even further south.

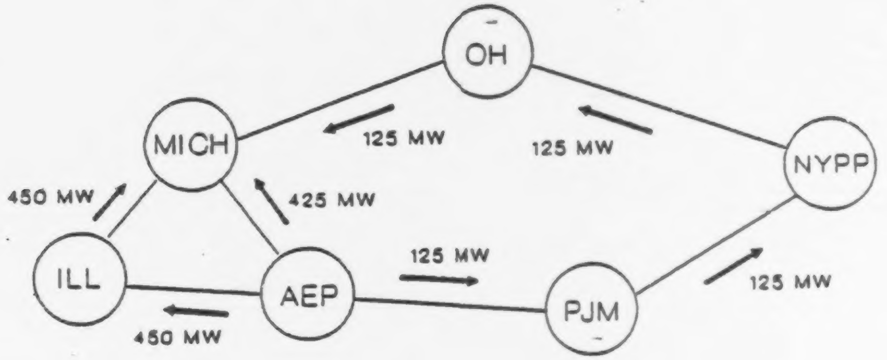

OH
MICH
NYPP
ILL
AEP
PJM

(A) Simplified representation of the Interconnected Systems in the Northern portions of the Eastern Interconnection.

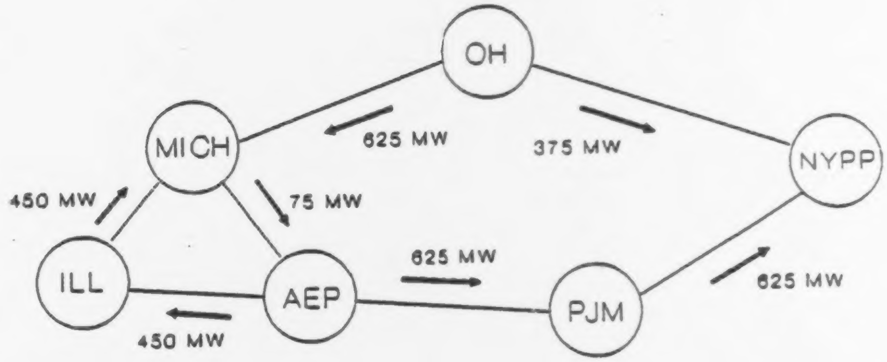

OH
MICH
500 MW
500 MW
NYPP
500 MW
500 MW
ILL
AEP
PJM
500 MW

(B) Appropriate Inter System Flows when OH schedules a 1000 MW to the NYPP System

Figure 4.2 - An Illustration of Loop Flows in the Eastern Interconnection


OH
MICH
NYPP
ILL
AEP
PJM
125 MW
125 MW
450 MW
425 MW
125 MW
125 MW
450 MW

(A) Approximate Inter System flows when AEP schedules 1000 MW for delivery to the Michigan Systems


OH
MICH
NYPP
ILL
AEP
PJM
625 MW
375 MW
450 MW
75 MW
625 MW
625 MW
450 MW

(B) Approximate net flows resulting from the two simultaneous interchange schedules.

Figure 4.3 - The flows for a scheduled interchange of 1000 MW from AEP to the Michigan Systems. (B) The combined effects of the OH-NYPP and AEP-Michigan Interchange.

Next consider the second transaction shown on Figure 4.3 (A), the delivery of 1000 MW from the AEP system to the systems in Michigan. In this case about 425 MW would flow over the contract path and the remainder would be distributed approximately as shown. Note that about 125 MW (12.5%) flows east and north through PJM, the NYPP and OH. Again the illustration is simplified in that some of the systems that might actually be involved have been omitted.

If both of these transactions are scheduled simultaneously, the net effect on the individual interchange boundary circuits between the various systems is shown on Figure 4.3 (B). Note that in some cases the total flows are additive. For example the flows between PJM and NYPP, between AEP and PJM and between OH and Michigan are all increased to a level of 625 MW. On the other hand, the flows on some paths are decreased. In this example the contract path between AEP and the Michigan systems is only carrying a flow of 75 MW into the AEP system.

With a number of interchange transactions taking place simultaneously on an interconnected system, it becomes an increasingly difficult task for the system operators to schedule transactions in such a way that loop flows do not cause undue hardship on the interconnected systems that are affected. These flows cannot be allowed to overload circuits nor to constrain the operation of the utilities that own the transmission circuits effected by loop flows. This requires that equitable arrangements be in place and that system operators must have data available concerning the schedules and conditions on interconnected systems.

The loop flow phenomena contributes to the limitations of flows on transmission systems and increases the difficulties in precisely defining the available, unused transmission capacity.

All of these network related flow phenomena, the distribution of power flows, the automatic redistribution that takes place when system conditions change, and the effects of loop flows resulting from interchange transactions are complex, take place rapidly, and require close coordination between interconnected systems. The need for this coordination and information exchange has grown as the number of transactions being scheduled has increased.

4.4.3 Voltage-VAR Problems

When power systems are designed and operated such that VARs must be transmitted along a transmission line the VAR flow will cause a voltage drop along the line. The network voltage profile (i.e., the magnitudes of voltages at key points in the network such as line, generator, and substation buses) must be restricted so that voltage control devices (i.e., transformer tap changers, variable VAR supplies, etc.) are within their control ranges. If they are not, the voltages at customer loads may be outside of the range allowed by the standards.

Voltage-VAR flow problems may cause operating restrictions and circuit loading limitations that arise out of system operating security practices similar to those discussed above [66, 67]. One "generic" example arises when a system is importing a substantial portion of the power to serve the load in its territory. Under normal conditions the circuits are well within their thermal capacity, and voltages are within tolerance. The imported power is being transmitted via a transmission link that may fail and shutoff the power flow suddenly. If the importing system is interconnected with other utilities, the lost power will be made up in a large portion by the inflow of power into the system that takes place automatically as the entire interconnected system attempts to maintain the proper balance between supply and demand. This unexpected heavy flow into the area is accompanied by heavy VAR flows, depressing the voltage dramatically at the receiving system. Given the right combination of circuit elements and power flows, the voltage may be depressed to the point where the entire receiving system collapses. That is, the voltage declines are accompanied by additional VAR flows which, in turn, result in further voltage declines [68 - 71].

Power flow distribution and voltage-VAR problems are closely interrelated. For a given transmission line the magnitude of VAR support required for the terminal voltages is dependent upon the power flow on the line. An example is shown in Figure 4.4 which demonstrates the total reactive power in terms of millions of VARs (MVAR) required to transmit a given power flow over a 345 kV line which is 100 miles long, in order to keep the voltage magnitudes constant at each end at their nominal levels.

Suppose that this represents the characteristics of each circuit section on Figure 4.1 and one of the sections were to go from a situation where it was carrying 600 MW to one where it was carrying 1200 MW. The total VAR requirement for the section at a power flow level of 600 MW is about 80 MVAR. When the parallel section is removed and the loading goes to 1200 MW, the VAR requirement increases to about 700 MVAR in order to hold the voltage at its rated value. Some of these VARs will be transmitted over the line and some must be supplied at the load end of the line. Transmitting the VARs increases the current flowing on the line, using additional line capability. Designing the network to survive this situation requires a substantial installation of VAR generating equipment at the receiving end. Failure to supply the required VARs will result in a lowering of the load end voltage. If it is too low, the system may collapse.

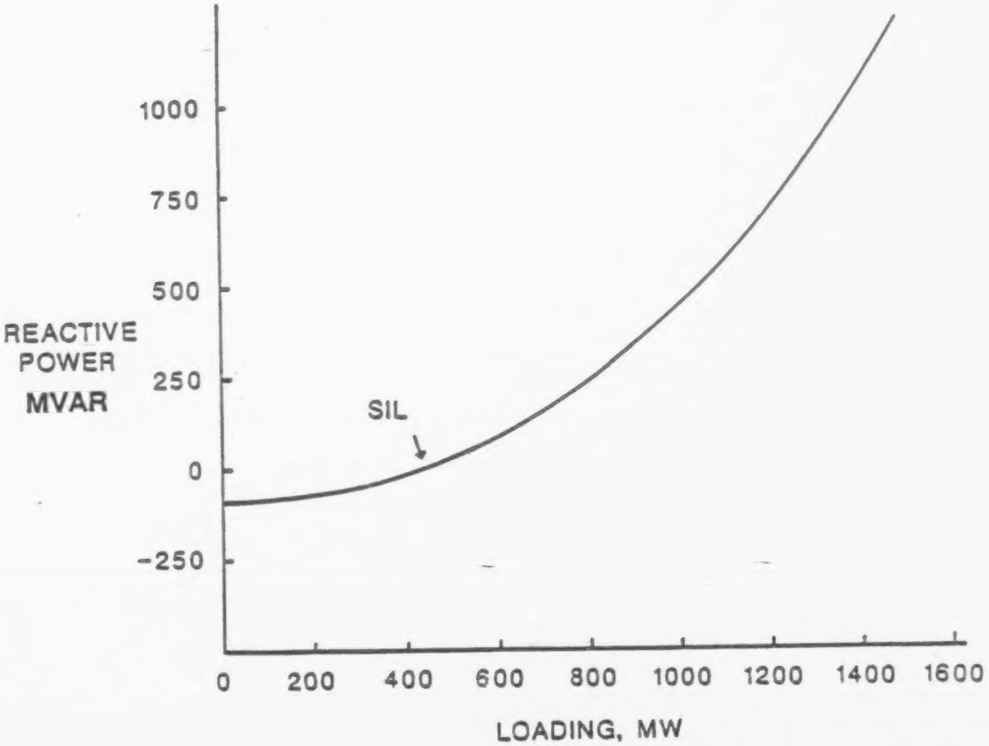


Figure 4.4 - VAR Requirements at Both Ends of a 100 Mile Long 345 kV Circuit. Surge Impedance Loading Level (SIL) corresponds to zero MVAR.

A similar situation may arise when high voltage transmission lines interconnect two systems. Figure 4.5 shows three interconnected systems. A and B are interconnected by two 100 mile long 345 kV lines. System B is interconnected to C by a dc line that normally carries 1100 MW into B. Simultaneously B is importing 900 MW from A. System A represents the rest of the interconnection and is very large in comparison to system B. Under normal conditions the 900 MW flowing from A into B requires practically zero VAR supply since the 345 kV lines are operating near their surge impedance loading level.

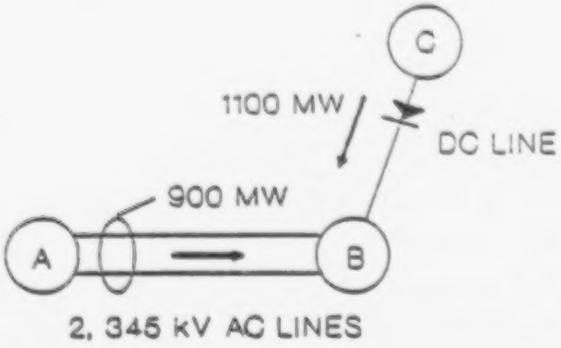


Figure 4.5 - Three Interconnected Systems showing 2000 MW import to System B. If the dc circuit is lost the flows on each 345 kV line will increase to almost 1000 MW.

Assume that the dc circuits linking systems C and B are suddenly lost. The loading of the 345 kV lines interconnecting A and B will increase to almost 1000 MW each as the power flows into A to attempt to bring the load and generation into balance. The 345 kV circuits are within their thermal limits, but the total VAR requirements to support the voltages have increased to about 1000 MVAR. If the VAR supply is inadequate, the voltage in system B at the 345 kV terminal could collapse, requiring load shedding and probably system separation from the rest of the interconnection.

Possible cures, or operating precautions that may be required, may include the restriction of the level of power imports so that the loss of the source will not cause a major outage, the installation of additional emergency VAR compensation, or the restriction of normal power flows on the interconnecting transmission circuits so that an occurrence of this type of event will not result in a voltage collapse.

This type of security consideration is important in current system operations. In the eastern portion of the U.S. large blocks of power are being supplied from a single Canadian system, Hydro-Quebec. In the western interconnection, high capacity dc links exist, which are used to transmit blocks of power between the Pacific northwest and the southwest areas. Both of these examples require that system operators and planners give consideration to this type of situation in order to prevent widespread circuit interruptions [20].

4.4.4 Stability Problems

Power systems also may suffer from dynamic problems where power flows oscillate at low frequencies [42]. The generators on a synchronously interconnected system all rotate in such a way that the electrical angles between their rotors (i.e., between the generated voltage phasors) stay within reasonable bounds relative to each other. The power transfer over a given element or circuit in an ac system depends upon this angular difference. If some sort of disturbance (e.g., a line fault near a generating station) occurs, the angular differences will change because power flows are altered and cause the power output required from the generators to change. The electrical power requirement from a generator may be suddenly reduced due to the fault and the mechanical power developed by the driving turbine stays constant, causing the generator to accelerate, increasing the angular difference. When the fault is removed by opening the faulted circuit, the power flows will again be altered and the angular difference decreased as the unit slows down. This will result in low frequency oscillations of the generator rotors and power flows in the network. If these are not damped out naturally or by the actions of various control systems, the system is unstable and usually requires switching operations to separate the system in order to restore normal conditions.

This dynamic instability is like the phenomena that may occur on a heavily travelled highway. As long as traffic is moving at a relatively constant speed, the vehicles will space themselves such that no "interference" results. However, when a sudden change occurs (e.g., a vehicle decelerates rapidly because of a tire blowout or to avoid some sudden intrusion into the traffic pattern), the spacing between vehicles is no longer static, but changes with time as each driver responds to the conditions he sees. The results depend on the initial spacings and velocities, the speed of response of the drivers and a host of other conditions. What would be a minor disturbance in the traffic flow pattern on a dry, sunny day may be a major accident during a rainy early evening period. If traffic volume is heavy and the average vehicle speed is high, the minor disturbance may result in a chain of accidents. The same is true in a power system where a minor transient event will result in a fleeting disturbance with one load-generator pattern and cause a major instability under different system conditions.

The possibility of transient stability problems interfering with system operation is investigated by system engineers using complex computer programs that must represent the generator, controls and load characteristics as well as the network. For systems with long, high reactance lines this may be a major concern because of the effect of the line reactance in limiting power transfer.

One technique to alleviate the problem is to reduce the loading on long circuits. Other methods include using intermediate switching stations to reduce the shock to the system when line sections must be removed and to use methods for reducing the effective line impedance. Rapid (i.e., high speed) breakers may be used to clear faults more rapidly than normal breakers [72]. Modern control systems on generators and their prime movers may also assist in solving these problems by providing rapid actions to damp out the oscillations [73 - 80]. Fast valving may be installed on the steam turbine to adjust the mechanical power input to the unit. Breaking resistors may be switched in near the generator to absorb the power causing the unit to accelerate [81]. It may be necessary to trip generators and reduce the power input rapidly to the unit (i.e., fast runback.) Modern excitation systems with stabilizers can assist in controlling these dynamic problems.

Subsynchronous resonance is another type of dynamic problem that occurs in systems; usually systems with longer lines which have series capacitors installed to reduce the overall impedance of the line [82 - 87]. In some systems that have steam turbine generator plants at the ends of long high voltage circuits, low frequency oscillations are sometimes excited that are amplified by the resonant interaction of the stored energy transfers between the electrical system and the rotating masses of the steam turbine generators. These steam turbine units have resonant mechanical frequencies which are less than the 60 Hz of the electrical system. Occasionally, if the electrical network parameters are of exactly the right magnitude, the mechanical and electrical systems have resonant frequencies which are close enough so undamped oscillations may occur. If these persist, shafts on the steam turbine units may break.

There are other mechanisms that may result in this phenomena, but the one cited above seems to be the major cause. There are several methods used to cure this problem. The electrical and/or mechanical systems may be detuned by changing shaft dimensions or modifying the electrical network. A less expensive technique is to use filters in the electrical system to block the low frequency currents or to remove them from the network. The low frequency currents may also be detected and used as a signal to remove the generator.

4.4.5 System Operating Security

System operating security considerations and policies on the interconnected system affect transmission limitations to a great extent. These are concerned with maintaining operating states such that instability, uncontrolled separation of systems or cascading outages will not result from the occurrence of credible contingency. The NERC guidelines refer to single, most served contingencies as being a requirement with multiple contingencies being an optional requirement to be met when practical [25].

These guidelines result in systems being operated in a defensive mode with some system operators using single contingency, worst case conditions (the N-1 criteria) and others using multiple contingencies involving combinations of 2 outages to find the worst case scenarios (the N-2 criteria). The worst cases found by applying these guidelines changes with loading patterns, unit and line maintenance outages and so forth.

The adoption of these policies has increased the operating security of the interconnected systems and undoubtedly reduced the frequency of occurrence of major disturbances. Utility operators make every effort to prevent cascading outages from occurring using security constrained scheduling methods, to confine the effects of a major bulk power outage to a restricted area by using planned system separation when required and to develop plans and schemes for restoring service rapidly when and if a blackout or system separation occurs.

These measures include the provision for running sufficient generation capability to provide operating reserves; that is, there must be an adequate amount of generation online in excess of the load demand and in the right locations so that contingencies can be survived. Reactive power sources are made available to handle emergencies. Transmission systems are operated within normal ratings and transmission system operation is coordinated amongst interconnected systems, control areas, pools and regions.

The effects of these requirements are generally to reduce the transmission system loadings well below thermal capabilities in order to have the reserve capacity that is required to handle contingencies. Generation and VAR supply schedules are developed using contingency analysis methods that include consideration of post contingency loading conditions. Off-economy loading of generation is the price that is paid for these defensive operating tactics. Methods for alleviating system overloads are incorporated in many system control center systems that detect existing or possible abnormal system conditions and develop operating changes required to remove the problem.

These operating guidelines are not applied uniformly in all systems because of the many differences between individual system generation transmission, load area distribution and interconnections to other systems. Some systems use the single contingency criteria to find worst case situations while others use the double contingency criteria. Even if these operating criteria were to be applied uniformly, they would not result in identical system reliability levels because of the many differences between systems that exist.

The need to be concerned with system security is self evident. Widespread blackouts, blackouts that persist for days and outages that coincide with severe weather may cause widespread economic losses and endanger the health and safety of large groups of people. There is a tradeoff between these security concerns and the economics of the electric utility system. As in any situation involving a tradeoff of this nature there are bound to be differences of opinion concerning the "optimum" level of reliability/security.

Allowing that these differences may exist and that there may be more than one single "best" mode of operating a system, means that the definition of available transmission capacity will vary from system to system and may even vary from time to time on the same system.

The resources required for determining transfer capability limitations based on steady-state network conditions include:

1. an adequate load flow computer program (that is one sufficiently large to represent the utility network of concern and its interconnected neighbors - 2000 to 4000 bus models are common),
2. the data base describing the network, loads and generation system, and
3. a knowledge of the generation dispatching practices.

Studies to determine transfer capacities are normally conducted by committees of power system planning engineers from interconnected companies. Security constrained dispatching is performed in the most modern control centers by the dispatchers in a real time control mode.

CHAPTER V

CHAPTER 5

IMPROVING OPERATIONS OF CURRENT SYSTEMS

5.1 INTRODUCTION

The current arrangements for planning, engineering and operating the power systems have evolved over the years in diverse fashions in various parts of the U.S. The methods and arrangements used vary according to the type of system, the patterns of generation and loads and the degree of participation of a system with its interconnected neighbors.

The individual utilities are quite efficient in their operations. Unit heat rates are monitored carefully and units maintained regularly to keep generation capacity in a good state of repair. All systems with generation operate with an economic dispatch. There appears to be a regular and increasing tendency on the part of systems with higher operating cost capacity to seek out more economic sources of power to purchase. One well known example is the growth of imported power from Canadian sources to displace higher cost, oil fired generating capacity.

As was pointed out in an earlier chapter, there are a number of regions where centrally dispatched power pools have been formed to coordinate the plans for system development and operate the systems economically to reduce both long run investment costs and short run operating costs. These have taken the form of power pool agreements amongst unaffiliated utilities and the coordinated operation and planning of the large utility holding companies.

These existing operations offer the outstanding example of a practical and tested way of improving overall efficiency of the utility systems in other areas.

5.2 IMPROVING EFFICIENCY - BENEFITS OF POWER POOLING AND BROKERS

A recent article by Mr. John Casazza presents an excellent summary of the results and obligations of power pools [88]. To quote:

> "We have been tracking the savings resulting from interutility coordination and pooling ever since the 1964 National Power Survey which stressed the need for increased coordination. Our most recent evaluation of the benefits showed total national reductions in excess of $15 billion per year in the bills electric consumers paid in the last few years because of interutility coordination. These annual savings are expected to increase to more than $20 billion by the mid-1990's. About three-quarters of these savings are due to reductions in capital investments and about one-quarter to fuel cost reductions."

These economic gains are substantial and no doubt could be augmented with an increased level of power brokering, pooling, and central dispatch systems.

The benefits of pooling are balanced by responsibilities of the pool members to deal openly and fairly with each other and to exchange data freely concerning future load projections, expansion plans and operating costs. Centrally dispatched power pools require the investment in a pool control center, communications and computer facilities and the support of an adequate engineering and dispatching staff. These are not inconsequential costs. Ranges of initial costs for a large pool control center have been informally given at levels of 10 to 50 million dollars. A support staff of 30 to 40 professional level people might require an ongoing cost of 3 to 5 million dollars per year.

These costs must be compared to possible reductions in system expansion cost savings and annual operating costs savings that may be obtained from a central dispatch system for a large enough pool. A system with a peak load of 10,000 MW and fossil fired generation would be expected to have an annual fuel bill in excess of a billion dollars per year. An operating cost savings of one-half per cent would be 5 million dollars per year; enough to pay for the pool operating staff costs sighted above.

The larger block of savings cited in the article quoted are due to the reduction in facilities required to handle the load growth in a region when the interconnected systems plan and implement system expansions on a coordinated basis. Generation installed reserve requirements are reduced when systems can substitute lower cost interconnection capability that allows them to share generation reserves for new generation capacity. This is quite feasible and has been done in all of the power pools over the years.

The pool planning organization, whether a holding company staff or a committee organized from unaffiliated pool members, may plan for adequate reliability and lower generation reserves by taking advantage of the diversity in loads, the diversity in both planned and forced outages, and by coordinating capacity additions so new facilities are installed on a pool need basis rather than by each individual system. Transmission plans can be studied and implementations developed that will provide adequate transmission for exchanging power and energy on a regular and emergency basis.

In the power production area the coordination of operations on a pool wide basis rather than on individual system basis means that the most efficient units within the region are being used to produce the energy required by customers on a planned minimum costs basis. The consumers' costs are reduced overall by this production efficiency.

Arrangements can be made to allow the use of the entire transmission system within the pool area for the mutual benefit of all of the pool members. In most pools ties are "free flowing" eliminating the requirement for complex wheeling contracts. If transmission ownership is unbalanced, arrangements can be made to share transmission costs on a relatively simple basis. New transmission capacity may be planned jointly to develop optimal systems at the lowest costs.

The individual systems must relinquish something for these benefits. They must support the pool operation, both with sufficient funding and with adequate engineering support. The operating arrangements mean that the most efficient production units in the pool will be operated to supply customer demands throughout the power pool. The owners of these units must receive fair compensation and the purchasers of the energy must be charged a fair price. The arrangements to accomplish this may require some negotiation and time to develop and implement.

Individual system members of a pool must agree to complete exchange of data and forecasts, which has been encouraged by the generally non-competitive environment that utilities have been operating in to date. The members must be willing to coordinate plans and system developments. They must agree on generation plans and transmission system construction. They must be willing to surrender some of their responsibilities in operations and scheduling to the pool center. Finally they agree to coordinate plans to avoid system emergencies, plans to coordinate corrective actions during emergencies and plans to restore service after an emergency does occur.

It is logical to ask at this point why there are not more power pools of affiliated and unaffiliated utilities. The answer is not clear. The potential savings in operating costs do require a fairly large pool size to support the annual costs of the pool operation. The individual utility does not escape the need for its own operations control center by belonging to a power pool of unaffiliated companies. (A holding company may be different with all of the generation operated by a centralized staff of the parent or one of its service company subsidiaries.) A substantial portion of the available operating savings may be achievable by other means such as economic interchange, power brokers or long term interchange agreements.

There is also the very human reluctance to surrender a portion of the individual system's management responsibilities and authorities to a pool structure. This may be amplified by the regulatory structure. Multi-state pooling may be discouraged by the natural parochial interest of state regulatory agencies. The coordination of pool operations requires an investment in manpower for the proper functioning of the various committee structures. Individual utilities may feel that they are meeting their service obligations to their own customers in an optimal fashion and believe that a centrally dispatched power pool would be superfluous.

Power brokers are one effective response to the reluctance to form additional centrally dispatched power pools. At their simplest, they organize a regional market for economic interchange that has been handled by direct negotiations between individual buyers and sellers. At their most complex, they arrange for interchange transactions amongst the participants and monitor the performance of the market in saving production costs.

Their advantages, compared to a centrally dispatched power pool are the simplicity of the arrangements required, and the relatively low cost of the broker operation.

Their chief disadvantages, again compared to the centrally dispatched power pool are in the lack of a method for effectively coordinating planning and system development and the fact that participation is generally voluntary. In broker schemes installed to date, some types of economic interchange transactions performed routinely in a central dispatch do not take place in a power broker scheme because of the particular operating rules implemented.

Another option to improve operating and planning efficiency is to foster the formation of more integrated utility holding companies on a regional basis. These organizations could perform the planning and system development coordination as well as the central dispatch of the generation. With a proper organizational structure and regulatory environment, the centralized holding company operations could consolidate many of the planning and operating control functions performed locally at present.

5.3 POSSIBLE IMPROVEMENTS IN SYSTEM OPERATIONS AND CONTROL

The improvements possible in individual system's operations and control are highly specific to the system and its current control system. This section will address two broad topics, the effects of reliability criteria on system operations and generally needed improvements in control of system operations.

5.3.1 System Operating Reliability Criteria

This subject has been discussed repeatedly in the preceding chapters since it affects the transmission capacity that is effectively available for normal system operations when systems are dispatched in a defensive mode to prevent cascading failures.

There is a need for a simpler technique to classify available transmission and transfer capacities if the transmission system itself is to be made available for access by non-utility parties. Even without that consideration, the adoption of some simple scheme for determining the available transmission capacity would be advantageous in developing system schedules and arranging interchange schedules.

This is an analytical issue that needs further attention. The diversity between systems and their patterns of load and generation complicate this issue. Even geography plays a significant role. Take the peninsular portion of Florida as an example. The electric power systems in this region are interconnected to the north with a limited number of high voltage circuits that generally are scheduled with heavy economy interchange power flows. If these should fail, these systems would essentially be isolated from the rest of the Eastern Interconnection. It is natural that the operators in this area would prefer a more conservative approach towards system reliability-security.

One possible approach to defining available transmission capacity would be the adoption of a single security criteria for all of the systems. With the current schemes this would be the single contingency worst case. Another approach might be to base the development of reliability criteria for system security on a probabilistic assessment of the reliability level. This requires that system operating data be collected and analyzed in more detail than at present. It also complicates the possibility of developing a single, simple criteria.

One engineering approach that might be tried is that of correlating the transmission and transfer capability levels developed using current schemes with the actual physical capabilities of the circuits involved. It may well be that there is a simple correlation in some systems which can be used to define transmission capability.

There is an alternative to defensive generation scheduling system operations, that of developing means for reacting rapidly enough to prevent cascading failures after a contingency has occurred. To be effective, corrective actions should be triggered automatically and flow distributions should be readjusted rapidly enough to prevent further circuit outages. For example, if emergency ratings are allowed for a 15 minute period, the corrective action should restore flows so that normal ratings are not exceeded within that time period.

Corrective actions could involve tripping units to relieve overloads and alleviate stability problems, automatic load shedding to relieve generation - load imbalances or circuit overloads, rapid insertion (or removal) of circuit impedances to redistribute power flows after a contingency. These methods have been used in specific cases but have not been widely applied to date. They must be carefully studied and applied if they are to achieve the same level of system reliability as achieved by the defensive scheduling techniques.

A recent NERC publication refers to these reactive protection schemes as "special protection systems (SPS)." [20]. The reference points out that these schemes are being considered more frequently as an alternative to defensive generation scheduling. The authors note that there is a concern that the widespread application of these complex schemes may become a matter of concern in future power system reliability since the system security is dependent upon the correct functioning of these special protective systems.

5.3.2 Possible Improvements in Systems Operations and Controls

There appears to be a need for better coordination between power plant control schemes and system operating controls. The rapid response of power plants aids in the maintenance of system frequency, the amelioration of system dynamic problems and in the rapid reduction of network overloads by shifting generation. In the past boiler and plant controls have been fairly slow with the control design limiting steam plant response rates to maximum response rates of 3% of the plant's rating per minute. With more modern boiler controls this trend does not appear to have changed. This observation is based on reports from system operators who have noted (informally) a trend towards poorer frequency control performance.

In the system control center and dispatching area there is a need in the larger interconnections in the east and west for the more rapid, automatic and complete exchange of current operating data amongst systems. There is currently a movement to develop a data exchange protocol and system for the exchange of data between interconnected systems [89].

In the past 15 to 18 years many systems have developed improved system monitoring and data communications systems at which allow the operators to use actual network condition data in the operating control systems. These systems may be extended so operators in one system have the capacity to observe and monitor conditions in adjacent systems. Some of this need, if not all, may be satisfied by the development of a rapid data exchange system.

Table 5.1 below lists operations and control actions that may be used, or implemented, to enhance transmission system capability. The data in the table indicates options available for central energy management systems. They are grouped by the system sector affected, demand, power production and the network. The entries in the columns indicate the primary and secondary purposes of the listed control action [90].

TABLE 5.1

Operations and Control Actions for Enhancing Transmission Capability

			AVOID INSTABILITY				
	POWER BALANCE	OVERLOAD CASCADE PREVENTION	STATIC/ DYNAMIC	TRANSIENT	VOLTAGE	CONTROL SEPARATION	IMPROVE RESTORATION
DEMAND							
VOLTAGE REDUCTION	P(1)	S(1)					
LOAD MANAGEMENT*	P	S					
LOAD SHEDDING*	P	P	S	S	S	P	P
PRODUCTION							
GEN DROPPING*	P	S		P		P	
GEN RUNBACK	P					S	P
DYN. BRAKING				P			
FAST VALVING				P			
FAST EXCITATION *				P	S		
STABILIZER				P	S	S	S
BY-PASS VALVING*							P
OPERATING RESERVE*	P(2)						S
REMEDIAL DISPATCH*	P(2)	P	P(2)	P(2)	P(2)		
WHEELING SUSPENSION*		P	P(2)	P(2)	P(2)		
TRANSACTION SUSPENSION*		P	P(2)	P(2)	P(2)		
PROD. RESCHEDULING*		P					
NETWORK							
AUTO RECLOSE							
HIGH SPEED		S		P			P
SLOW SPEED		P					P
LINE SWITCHING		S				P	S
NETWORK SECTIONING*	P	P				P	S
VAR/VOLT CONTROL*		S	P		P		P
SERIES CAP INSERTION		S	P	P			
EMERGENCY RATING		S					

NOTE: (1) P refers to primary intent and S to secondary intent of action/control

NOTE: (2) refers to action under security constraint (contingency anticipation)

* Refers to actions which related to energy management system actions

CHAPTER VI

CHAPTER 6

PROSPECTS FOR INCREASING TRANSFER CAPABILITY

6.1 INTRODUCTION

Table 6.1 summarizes the transmission limitations discussed in Chapter 4.

TABLE 6.1

Transmission Capability Constraints

Individual Line Constraints

- Voltage Constraints
  - line design parameters
  - terminal equipment ratings
- Current Constraints
  - conductor sagging
  - conductor lifetime
  - terminal equipment ratings
- Reactance

System Operating Constraints

- Distribution of Power Flows
- Loop Flows
- Voltage-VAR Constraints

Dynamic and Transient Stability

- Economic Dispatch, Scheduling
- Security Constrained Dispatching

Possible remedies are summarized in Table 6.2

TABLE 6.2

Possible Technological Remedies to Increase Transmission Capabilities

REMEDIES TO PHYSICAL CONSTRAINTS

Remedies to Individual Line Constraints

Voltage Uprating

- Tower Extensions
- Improved Insulators
- Non-standard Voltages
- New Terminal Equipment
  - (circuit breakers, relays, transformers)

Current Uprating

- Dynamic Conductor Rating
- Sag Assessment and Monitoring
- Restringing (live-line restringing)
- Changing Operating Standards

Tower Design and New Lines

- Conversion to Multiple Circuit Towers
- High Voltage Direct Current Lines
- Multiple Phase Lines
- Live Line Construction

Remedies to System Operating Constraints

Loop Flow Control/Load Division

- Redispatch of Generation
- Phase Angle Regulators
- Series Reactance aNd Capacitance
- System Reconfiguration
- HVDC Control Features

Reactive Power Management Techniques

- Shunt or Series Capacitors
- Shunt Reactors
- Static VAR Compensators
- Synchronous Condensers
- Generators as VAR Sources

TABLE 6.2 (continued)

Remedies to Dynamic and Transient Stability Constraints

Remedial or Reactive Measures

- Reducing Clearing Time
- Series Capacitors
- Rapid Adjustment of Network Impedance
- Generator Tripping and Fast Runback
- Fast Valving
- Braking Resistors and Load Switching
- High-Speed Reclosing
- Advanced Excitation Systems and Stabilizers
- Transient Excitation Boost
- Fast Acting Phase Angle Regulators
- Generator Reactors
- SVCs and Synchronous Condensers
- Sectionalizing (Adding Switching Stations)

The methods to relieve the physical transmission limitations all involve physically enlarging the transmission capability in a system [47, 48, 50, 91 - 93]. They may increase transmission capabilities in some systems by substantial amounts. All of these methods are expensive and may require the removal of the circuits involved for a prolonged period.

The construction of new circuits has been the preferred method to increase transmission capacity throughout the past development of the utility systems. The current difficulties with obtaining rights-of-way and permits to construct new circuits coupled with the decreasing load growth rates of recent years have made this a more time consuming, more expensive and less likely alternative.

6.2 LOAD DIVISION LIMITATIONS

The previous discussions point out the limitations that may arise due to the automatic, instantaneous division of power flows amongst the transmission line in a network. One generic problem that has occurred a number of times in the growth of utility networks is the overloading of lower voltage lines that have been paralleled by the subsequent construction of new, higher voltage circuits. These low voltage circuits may be overloaded in normal conditions or when a parallel higher voltage line is opened (e.g., to clear a fault) and the power automatically starts to flow on the low voltage line. One practical and inexpensive method used to cure this problem is to open one or more breakers on the low voltage line(s) and operate them as radial circuits to deliver power to major load stations. This cures the overloading problem, but may reduce the reliability of supply to the load substations since these stations may now be served by only one circuit path instead of two or more.

Phase angle regulators, usually in the form of phase shifting transformers, may be installed in a circuit to increase or limit the power flow over a given line. Recall that the power flow on an ac line is proportional to the sine of the angle across the line. The phase shifter introduces a fixed angular difference in the circuit that must then be satisfied by the proper power flow.

Phase shifting transformers have not been generally applied. They introduce added requirements for VAR supply and their operating reliability has not been the best. Nevertheless, in some systems outside of the U.S. they are used quite frequently to control power flows over a few specific lines. Current costs for phase angle regulating transformers (as well as other remedies) are discussed later in the section on transmission costs.

It is possible that future developments in high power electronics may see the development of power flow control devices that permit the precise control of power flows over individual high voltage ac lines. Theoretically, this would now be feasible using existing high voltage, high power apparatus similar to that used in dc transmission circuits, but the costs would be very high.

Another method that may be used to limit the effects of load division is to introduce circuit elements in series with the lines to increase or decrease the effective line impedance. This method has been used to increase the stability limits of long high voltage lines by placing series capacitors in the line. The principle drawback has been where these series capacitors have led to the development of subsynchronous resonance problems.

The reconfiguration of the system on a temporary basis after the occurrence of an outage may alleviate the potential overloading of portions of the network.

The most widely used technique is to redispatch the system generation to relieve the load division problems. The system operators must have the system data available on a real time basis in the control center in order to accomplish this effectively and the control center must have the proper computer program routines available.

Redispatching the system generation increases the system's production costs and requires that enough capacity be available to shift generation fairly rapidly. Means are available to enhance the response and control characteristics of a great deal of existing generation. The technique is quite effective: cost penalties associated with non-optimal generation schedules are highly system specific.

6.3 VOLTAGE LIMITATIONS

Transmission limitations due to voltage related problems may be alleviated by a number of means. One large group of possible techniques is related to increasing the availability and controllability of VAR supplies on the system. Capacitors may be installed at stations to increase the available supply of VARs. They may be designed so that varying amounts of VARs are supplied by switching capacitors banks in and out of service. Series capacitors may be installed in series with lines to reduce the VAR losses in the line and increase stability limitations.

Synchronous condensers and static VAR compensators (SVCs) may be installed at the ends of circuits or in intermediate switching stations on long lines in order to provide a controllable source (or sink) of VARs. These devices are also used to increase the stability limits of longer high voltage lines. These techniques are quite effective. Typical costs for VAR supplies are discussed below.

Adding intermediate switching stations on long high voltage lines will reduce the increase in VAR losses when a portion of the network needs to be removed to clear a fault. This is true because the intermediate station reduces the increase in system impedance resulting from a switching operation. This is an effective but expensive remedy since additional busworks, protective systems and circuit breakers are required at each new station.

An operating technique that may be used (or required) is to run generators in or near the load areas to have available VAR supplies online to handle emergency conditions. Often, these are generators that would not be run under a normal economic schedule so this remedy also increases the system production cost.

A newer technique that is being more widely applied is to incorporate methods to dispatch VAR supplies at the same time that power generation is being scheduled [94 - 98]. These techniques, called "optimal power flows" are imbedded in computer programs designed to develop voltage-VAR schedules simultaneously with the economic dispatch of the generation system. They may be designed to recognize the possible effects of contingencies and are, thus, extensions of the security constrained dispatch techniques mentioned previously. To date (January 1988) these techniques have usually been used in an off line, or study mode to investigate and determine voltage-VAR schedules. It is anticipated that the future will see more applications in the real time control of the systems. The cost of implementation is that related to obtaining the required software. An approximate cost is in the neighborhood of $100,000 per installation. This would be expected to decline as more products enter the software market.

6.4 STABILITY RELATED LIMITATIONS

There are a number of techniques that have been used to alleviate stability related limitations. Some of these were mentioned in Chapter 4 when subsynchronous resonance was discussed. Most of the techniques mentioned below are related to the classical transient stability limitation or the dynamic problems causing low frequency oscillations of power. Their expected costs for implementation are highly dependent on the exact system conditions. They have all proven to be effective, but each situation requires careful examination.

Transient instability is initiated by the occurrence of a fault (i.e., a short circuit). Faults are removed by the combined actions of the relaying system which detects the fault and signals high voltage circuit breakers which remove the short circuit by opening the faulted circuit. The length of time required to clear the fault is an important determinant of the energy available to speed up the generator(s). The faster the fault is removed, the less the generators are accelerated, reducing the chance that the system will be unstable. Modern relaying and protective systems which have fast clearing times are available. These may be as low as 2 cycles (i.e., 1/30th of a second.) These may be installed to assist in reducing the effects of stability problems on transmission limitations [72].

Another way to reduce the potential effects of faults is to deliberately introduce additional impedance into the network to reduce the fault current that may flow when a line suffers a short circuit. Breaking resistors may be introduced into the network to absorb some of the kinetic energy in the generators that would otherwise serve to accelerate the unit when a fault removes the load on the machine [81].

The use of series capacitors on long high voltage circuits is a more-or-less standard way to reduce the effects of transient stability limits. The series capacitor reduces the circuit impedance, allowing a higher power transfer at a smaller angle difference across the network 99, 100].

Control schemes to reduce the loading on generators rapidly during severe faults will also help the stability problem [35, 76, 77]. "Fast runback" systems are designed to reduce loading levels while keeping a unit online. In the extreme, units may be tripped. Manufacturers of steam turbine generators generally do not recommend unit tripping since there is the possibility of damage to the shafts of the machines. Another variation of this technique is to combine the introduction of faster valving systems on the steam turbine-boiler system along with bypass systems to transfer steam that would normally be directed to the turbine into a bypass that directs it to the steam condenser. These methods have proven very effective in systems where severe transmission bottlenecks have occurred. Steam by-pass systems appear to have been used more in European practice than in the U.S.

The severity of faults may also be reduced by the use of rapid reclosing of circuit breakers or single pole, circuit breaker switching schemes. Many short circuits that occur on transmission systems are of very short duration and are due to lightning strokes. Clearing the fault rapidly and then reclosing the circuit automatically after the fault has been extinguished by the automatic action of a lightning arrestor reduces the time the generators are accelerated and increases the chances for the system to restore itself to a stable operating condition. Reclosing is widely used on major high voltage circuits. One disadvantage is the possibility of causing shaft damage on the steam turbine generators if the reclosing is done at such a time that severe electrical torques are imposed suddenly on the units. This may happen, for example, if the switching isolates a unit and accelerates to the point where there is a large angular difference between its rotor and the rest of the system at the time of reclosing.

The usual configuration on a high voltage circuit breaker installation is such that all three phases are interrupted when the breaker is opened to clear a short circuit. The vast majority of faults on high voltage ac transmission circuits are caused by lightning and involve only one phase of the three phase circuits. "Single pole switching" schemes may be used where the protective system detects which phase is involved and only opens that phase to clear the fault [72]. This has the advantage that the power transfer over the line is not suddenly reduced to zero since the other two phases are still in operation. Therefore the electrical loading on the nearby generators is not reduced to zero and the units will not accelerate as much as they would have if all three phases had been opened. These schemes for special circuit breaker actions are not major cost items when compared to the breaker cost.

Advanced control systems in the form of modern excitation systems and generator stabilizers are being widely applied to both new and older units to ameliorate dynamic problems [73 - 75, 80]. These systems contribute damping to the system that serves to reduce the risk of instability. Increasing transmission system loading always increases the risk of transient or dynamic instability. These modern excitation systems and stabilizers reduce this risk and allow the increase in effective transmission capacity. They have proven effective in systems where they have been applied. Costs mentioned by stabilizer manufacturers range from $50,000 to $150,000 per generator unit.

Adding controllable sources of VARs also reduces the effects of stability on limiting transmission transfers. They are used frequently on long high voltage lines to support voltages and increase the likelihood that systems will remain stable after the occurrence of a fault [101 - 103].

Each system that has a dynamic problem requires a detailed investigation to find a suitable, economic method for remedying the condition. Care must be taken that the prescribed cures do not cause other problems. The classic case is the introduction of subsynchronous resonance problems in systems that had installed series capacitors to alleviate transient stability limitations. The interconnected power system is a complex electromechanical system with many levels of controls. The opportunities for interference and disastrous interaction between these is always a concern.

6.5 SYSTEM CONTROL LIMITATIONS

6.5.1 Security Related

The limitations on transmission transfers that arise from system control are primarily due to the concerns with system reliability and security. These are concerned with both dynamic operating problems and static problems that may arise after a contingency has been survived. If a contingency of some kind results in a post-contingency condition where elements of the transmission system are overloaded, the system operators have a margin in capability which is the excess capability between the short term emergency ratings and the normal capability ratings of he network elements. This emergency capacity is generally allowed to be used for 15 minutes after which the loadings are to be reduced.

If an outage or other operating problem does result in the need for drastic action, the operators should have a plan for carrying out this in order to minimize the consequences to the system. These emergency control schemes include:

- controlled separation of the system (sometimes called "islanding") that attempts to create isolated areas where load and generation are in balance,
- scheduled tripping of generation to restore the power balance,
- use of fast response VAR supplies,
- load shedding by reducing system voltage levels, using load management systems, appeals to customers, dropping interruptable customer loads and direct load shedding by dropping substations,
- redispatch of generation, and
- rescheduling of interchange transfers.

After the occurrence of a major outage which may have created islands where there is no generation, the system operators need an effective and efficient plan to restore the system to normal as fast as possible. This must include the capability to restart power plants that have no surviving connection to the system (i.e., "black start capability") that may require the installation of local diesel engine generators to provide the auxiliary power required to restart. Plans must be made and carefully followed so the system can be reconstructed and loads picked up in an orderly fashion that does not initiate further outages [104].

A common problem to be avoided is that of "backfeed" where a plant may energize the transmission system in areas where operators and line crews have assumed that they are deenergized. This is similar to the backfeed problem that arises in a prolonged weather induced outage in a distribution system. It is more than likely to be the case that one or more of the residential customers will have an emergency generator online. If the customers' connections to the system are not opened, the emergency generator may energize circuits that line crews have every right to believe are deenergized. Line crews attempting to restore service frequently must conduct door to door surveys to ensure that the system is not accidentally energized.

The existence of emergency control systems and restoration plans may make the utility operators more agreeable to a less conservative approach in the application of reliability criteria for the development of security constrained dispatches and interchange schedules and thus utilize more of the physically available transmission system capacity.

The relaxation of these reliability criteria (e.g., the use of a single contingency criteria rather than a double contingency criteria in developing secure generation and transfer schedules) is probably the most effective method to achieve an incremental gain in transmission capacity at the lowest initial cost. These reliability criteria establish the balance point between system security/reliability and system operating costs and transmission system utilization. The limits set by the application of these criteria are much less than the physical limits of the system components since the use of a security constrained schedule keeps transmission capability in reserve to survive the worst case contingency.

The other consequences of adopting less restrictive reliability criteria should be carefully considered before they are relaxed. These criteria have evolved over the past operating history of the interconnected systems as a consequence of the experiences with several major, widespread blackouts. As with any reliability criteria or standard, the acceptance of any criteria is very subjective and dependent on local conditions. The effects of a blackout in a large metropolitan area are apt to be much more severe to the consumers than to those in a small urban area or rural area. The interruption of production at an industrial plant certainly carries an economic penalty. But, what is the economic value of electric service where its interruption may endanger life and limb? Certainly these kinds of questions have answers, but not answers that we can all agree are universally applicable. The recent (1987) concerns over airline reliability and safety are one example of this disagreement.

The increase in the number of interchange transactions, the introduction of power broker schemes and the growth of non-utility power generators (i.e., cogenerators, qualified facilities and independent power producers (IPP's)) have increased the complexities of system operation and increased the security-related operating concerns. With the generation and transmission system operation under the control of the system operators, the responsibility for both economic and secure operation is in one place. The introduction of non-utility resources on the system divides this responsibility. For example, a cogenerator that is producing steam for an industrial process using a combined cycle plant may not wish to curtail its generation because of the need for process steam. The plant may, in fact, not be capable of producing the required steam flow without producing an excess of generation that must be absorbed by the rest of the system.

6.5.2 Power Plant Response

In the previous discussions of system dynamic problems and stability effects that may limit transmission utilization, the phenomena and control actions all take place in fractions of a second. In the redispatching of generation to avoid overloads the required actions need to be accomplished within the time period of the short term emergency overload rating of the transmission system components, usually 15 minutes. Therefore one of the factors to be considered is the ability of the system generation to be redispatched after a contingency within this period. That is, plants must respond usually within 15 minutes to put the transmission circuits within their normal ratings after an outage [105].

Hydroelectric units and gas turbine plants have very little problem in changing outputs within a short period assuming that they are not at full output. Steam units are generally capable of responding within this time frame, but may be limited by their control systems to a slower response rate [106, 107]. Governor response is not relevant in this connection. On the various interconnected systems the outages of even major power plants will cause only a small frequency deviation and the governor response is fairly rapid. The transmission overload problems are area problems and are therefore related to the slower control actions of the AGC systems.

Response rates of steam turbine units are limited to minimize the thermal stresses and possible metallurgical fatigue that could arise from frequent thermal cycling caused by rapid and frequent load changes. Response rates for steam units are typically limited by their controls to a maximum of about 3% of the unit's rating per minute. At any given time not all of the units on a system will be operating within control range. Some will be at maximum output because of economic operating schedules while others may be taken off control by plant operators to minimize wear on the unit and avoid future maintenance problems. It is quite likely that only 15 to 25% of the capacity online at any given time will be within control range.

Suppose that there is a 10% imbalance of generation and load in an area that has 20% of the capacity within the control range. At the maximum response rate of 3% per minute it will take over 15 minutes to restore the generation load balance. (That is, (10% MW)/(0.2 x 3% MW/Minute) = 16.67 minutes.) Protective relaying schemes may open essential interconnection circuits before the plants have responded to reduce the tie flows within the area. Therefore consideration of means to increase this response is important when considering transmission limitations. One effective technique is to require more units to be under AGC system control.

Unit loadings may be reduced rapidly by the use of the techniques discussed previously (i.e., fast runback, steam by-pass, etc.) The output of a steam turbine may be increased by several means. Going to overpressure operation or operating with the steam valves wide open may increase the maximum output by 5% each. It is essential that the generator have the capacity to produce this increased amount of power. If it is feasible, a high pressure feedwater heater may be removed (i.e., "cut out") increasing the available output by as much as 6%. The use of an auxiliary boiler and the lowering of reheat steam pressure on a reheat unit may increase the output by about 3% each.

It would not be expected that all of these measures could be used simultaneously on a given unit. But, it would not be unusual to be able to obtain a 10% increase in output. Operating plants in this fashion may place the plant at a greater risk of failure. The possible consequences of increasing plant output must be weighed carefully against the gain in transmission system utilization. The immediate cost of implementation may be low, but the long term effects must be considered.

6.5.3 Deliberate System Separation

One drawback to the interconnected operations of utility systems is the possibility of having to share load curtailments and possible sustained low frequency operation when an interconnected system suffers a severe outage. The AGC system operations (described in Chapter 3) are designed with the intent that each control area is responsible for satisfying its own demands. Power that is being sold, purchased or wheeled through the system on a scheduled basis, or is flowing through the system to satisfy the emergency regulation needs of an adjacent system, does not increase the area control error as long as the frequency deviation is small. At some point during an emergency the frequency deviation may cause the normal systems to begin to increase generation to satisfy the load demand on the interconnection and ultimately normal systems may start to shed load to preserve the interconnection.

In many regions system operators in adjacent areas have worked out arrangements for mutual assistance in cases of prolonged emergency operation. Voltage reductions may be deliberately imposed on the entire region to reduce demands. Interconnected systems with adequate generation may shed loads in order to preserve the integrity of the entire interconnected regional system. Deliberate system separation, that is, opening circuit breakers to isolate a system with a serious generation shortage (called "islanding" in industry jargon), is usually a last resort. It is done to prevent the generation shortage or blackout from expanding. Emergency plans will call for separation such that the load and demand balance can be maintained or restored within each island.

Another approach is possible and has been discussed informally by at least one midwestern utility, is to limit the sharing of load losses (i.e., reduced voltages and deliberate load shedding) when their system is itself satisfying the native demand with its own generation resources. The system would use a signal similar to the area control error (ACE) to detect and discriminate between internal generation shortages and prolonged shortages outside their system. If the frequency remains low indicating a generation shortage on the interconnection, and at the same time their internal load and generation is in balance, they would deliberately isolate their system by opening all of the ties to the interconnection to avoid having to curtail their own customers. This would be done automatically.

There is merit in both approaches, sharing in curtailments to preserve the interconnection or deliberately isolating a sound system to avoid importing a shortage. The voluntary agreements reached by non-competing, interconnected utilities to preserve the interconnection and share in the emergency procedures that may require load shedding undoubtedly has reduced the frequency of major, widespread blackouts. The emergency procedures for restoring service on an interconnection that has several islands after a major disturbance are complex and take a long time to accomplish. Preserving the interconnection throughout a disturbance means that power will generally be available to restart and resynchronize generators that have been shut down during the emergency. The few islands that may have been created can then be restored much faster.

On the other hand, an individual utility's primary operating responsibility is to provide service to its own customers. The deliberate separation of the system from the interconnection when prolonged emergencies elsewhere on the interconnection threaten to cause local service curtailments is viewed by some as a better path to follow. Certainly if this practice were to be adopted on a widespread basis it would tend to curtail transmission usage and in effect, make all interchanges subject to interruption more frequently.

6.6 TRANSMISSION COSTS

The estimation of transmission system costs for new construction and for augmenting existing systems' elements is difficult because of regional differences in construction costs, the differences in design and construction practices, and differences in land costs for stations and circuit rights-of-way.

Table 6.3 below lists the line design characteristics affecting construction costs [19].

TABLE 6.3

Line Design Characteristics Affecting Cost

Line voltage
Loading (megawatts)
Choice of annual cost or present worth analysis
Number of conductors in study
Insulation characteristics
Phase bundle configuration
Number of circuits
Span length range
Ground wires: diameter, weight, and cost
Phase spacing
Number, type, and cost of insulator units
Ice thickness
Wind pressure on conductors
Unloaded and loaded tension
Broken conductors and broken conductors tension
Allowable conductor temperature
Ground clearances
Tower type
Tower and foundation weight factors
Tower and foundation steel excavation and backfill costs
Tower setup and assembly costs
Pulling, sagging, and clipping costs
Loss factor
Plant cost
Energy cost
Interest rates
Grounding
Transpositions

The cost data in this section are quite approximate and are based upon published survey data, manufacturer's price handbooks and experience in assessing different proposed transmission schemes [108 - 111]. The data given are estimates of costs for various types of apparatus used in power transmission. In most cases a range of data are given that reflect the extent of data from different sources.

The major elements involved include:

- lines,
- circuit breakers and protective equipment,
- transformers, and
- VAR support and voltage control apparatus.

6.6.1 Line Costs

Line costs per mile vary with voltage level, type of tower construction (wood pole, lattice, etc.), number of conductors per phase, conductor size, tower design, etc. No simple estimating formula appears to be accurate for all cases although they may be for developing approximate values.

The 1987 NRRI report "Some Economic Principles for Pricing Wheeled Power" contains the results of a survey of line construction costs performed as part of the reported effort [19]. These data were analyzed and fitted statistically to develop estimated costs for various regions of the U.S. and for different voltages, etc. The results are summarized on Figure 6.1 which shows the approximate cost in thousands of dollars per mile as a function of the line voltage rating. The heavy line represents an approximate mean values for the various regional data and the bandwidth represents the range of cost data for different regions. Costs are in 1985 dollars.

These data show that the expected costs rise with voltage rating at a rate which is much less than one proportional to the square of the voltage level. Since the transmission capacity does increase approximately as the square of the voltage level, the cost per MW-mile of transmission capacity declines quite rapidly with voltage. The same report shows data indicating that the reported capacity costs declined from $1000 per MW-mile at 115 kV to $ 150 per MW-mile at 765 kV.

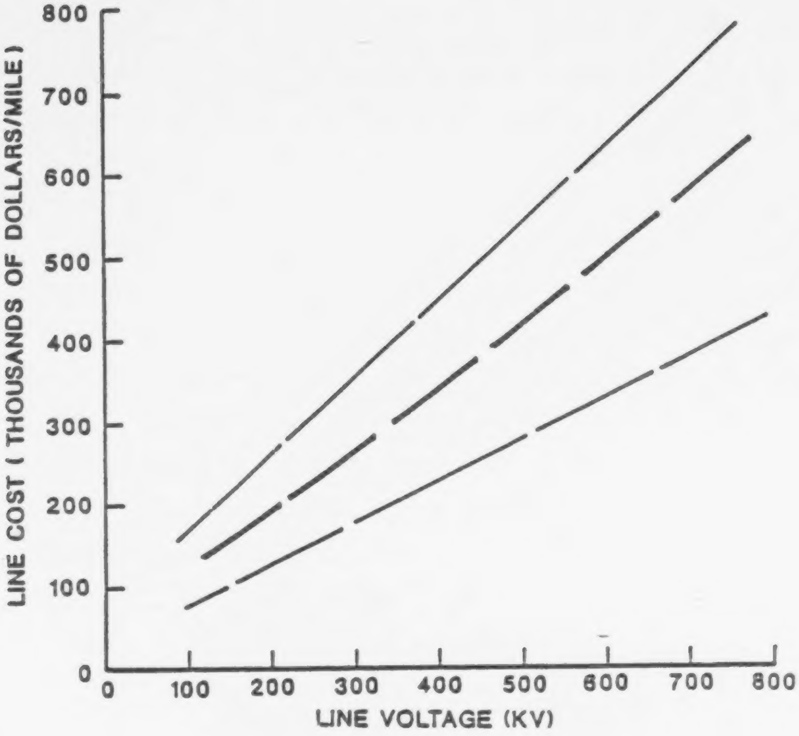


Figure 6.1 - Approximate ac Overhead Transmission Line Costs.

Source: **1987 NRRI Report " Some Economic Principles for Pricing Wheeled Power" [19]**

Direct current line costs are more difficult to classify since there have been so few examples. In some recent engineering planning studies estimated costs ranged about the same as those for the ac lines shown on the previous figure except that the line voltage has to be understood to mean the positive or negative dc voltage rating of the line. For example, a 138 kV ac line may have an estimated cost of about 130 to 150 thousand dollars per mile. A dc line with a positive and negative voltage to ground of 150 kV could be expected to have about the same range of costs per mile, 130 to 150 thousand dollars.

These data are in reasonable agreement with the data in the 1987 Oak Ridge National Laboratory Report [108]. That report presents an example showing that ac line costs are approximately $1,000 per kV per mile, where "kV" refers to the line voltage rating in kilovolts. They further cite an example of dc line costs that are approximately $800 per kV mile, where in this case the "kV" refers to the dc voltage to ground. Using these data a 138 kV ac line would cost $138,000 per mile and a ± 150 kV dc line would have an estimated cost of $120,000 per mile.

These and similar data should always be used with caution since the cost of right-of-way can influence actual costs greatly.

6.6.2 Circuit Breaker Costs

The installed costs of ac circuit breakers includes the cost of associated protective relaying and instrumentation systems. Data available are limited [108, 111]. Approximate installed costs are shown on Figure 6.2 as a function of voltage rating. Actual costs for specific installations will vary with the type of breaker, its interrupting duty rating, etc. Data obtained from planning studies show ranges of cost estimates that vary by 50 to 75% from the typical data on Figure 6.2.

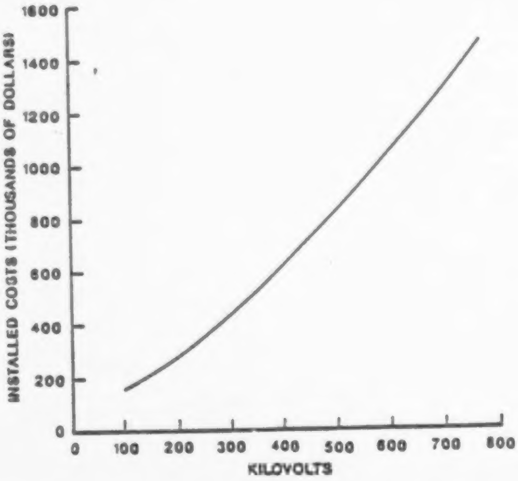


Figure 6.2 - Approximate Installed Costs of ac, High Voltage Circuit Breakers as a Function of Voltage Rating

6.6.3 Transformer Costs

Transformer costs are also a function of many parameters besides voltage. Some are two winding transformers, some have three or more windings and some are auto-transformers in which a single winding is tapped to transform voltage levels. Transformer cost data were obtained from manufacturer's standard, published data. (The specific transformer cost data below were obtained from published price data from Westinghouse. Catalogue price levels were adjusted to reflect current (1988) market conditions and are, therefore, "typical," data.) The costs given are the estimated purchased cost. Installed costs would range from 125 % to 200 % of the transformer cost itself.

Figure 6.3 indicates the range of costs expected and how they vary with size and the highest voltage rating. For a given transformer design type and rating in millions of volt-amperes (MVA), the cost per thousand volt-amperes (kVA) increases with the voltage level of the highest winding voltage. The upper curve on the figure is shown for a two winding transformer rated 120 MVA. The cost per kVA at a given voltage level declines with the rating of the transformer. The bottom curves indicate a very approximate range for transformer sizes which are appropriate for each voltage class. Generally two winding transformers are more expensive than auto transformers.

Phase shifting transformers are a special design of transformer and have a higher cost. Installed costs of regular transformers, including tap changers for voltage control, may range between a low of about 1.00 $/kVA up to 7 to 9 $/kVA. Phase shifting transformers will run in the neighborhood of 7 $/kVA and up.

Again, it should be realized that these costs are quite approximate and the cost of any particular transformer has to be determined considering a number of factors that may influence the design and therefore, the cost.

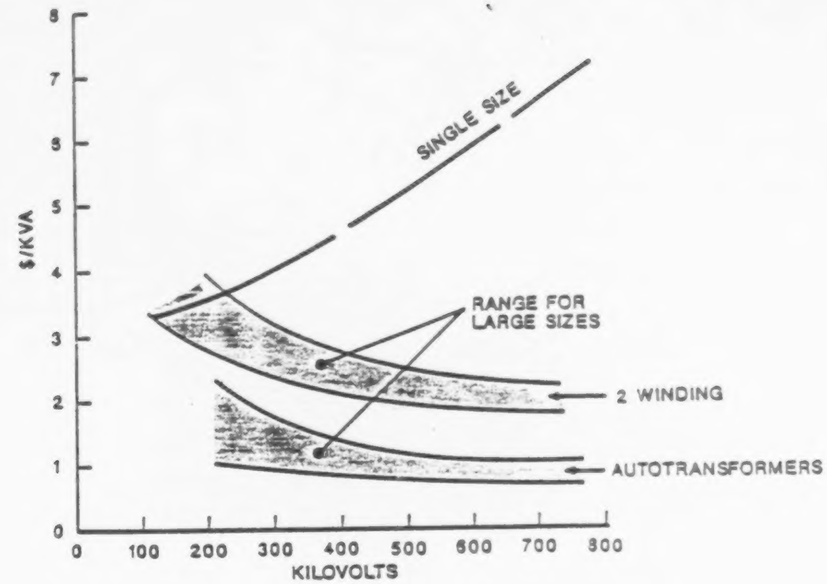


Figure 6.3 - Approximate Purchase Price of ac Power Transformers. Installed Costs Range from 125 to 200% of the Purchase Price.

6.6.4 VAR Supply and Voltage Control Apparatus

Shunt reactors that are applied to limit line voltage rises cost between 5 and 15 $/KVAR installed. Shunt capacitors may cost as low as about 4 to 5 $/KVAR for the capacitors alone. In switched banks, the installed costs are typically in the range of 13 $/KVAR. Series capacitors used to reduce series reactance effects cost between 8 and 13 $/KVAR.

Static VAR compensators (SVCs) are currently reported to cost 25 $/KVAR for sizes in excess of 50 MVAR and 30 $/KVAR for smaller sized installations.

6.6.5 Miscellaneous Costs

The costs for dc terminal apparatus, converters, invertors, harmonic filters, controls, etc. have run between 40 and 65 $/KW in recent studies based on manufacturer's data.

Underground high voltage, ac cable costs for high capacity installations run about 7 to 10 times the cost of an equivalent voltage class overhead transmission line. Underground cable costs are very site specific [23, 112].

6.7 APPROXIMATE COSTS FOR NEW AC TRANSMISSION

These cost data may be used to develop approximate installed costs for new ac transmission circuits. Figure 6.4 shows typical circuit capabilities as a function of the ac line voltage rating for 50 and 200 mile long ac overhead circuits which are based upon the surge impedance loading discussions in Chapter 1. The capabilities of the shorter length are typically limited by voltage-VAR limits and those for the 200 mile line by stability considerations.

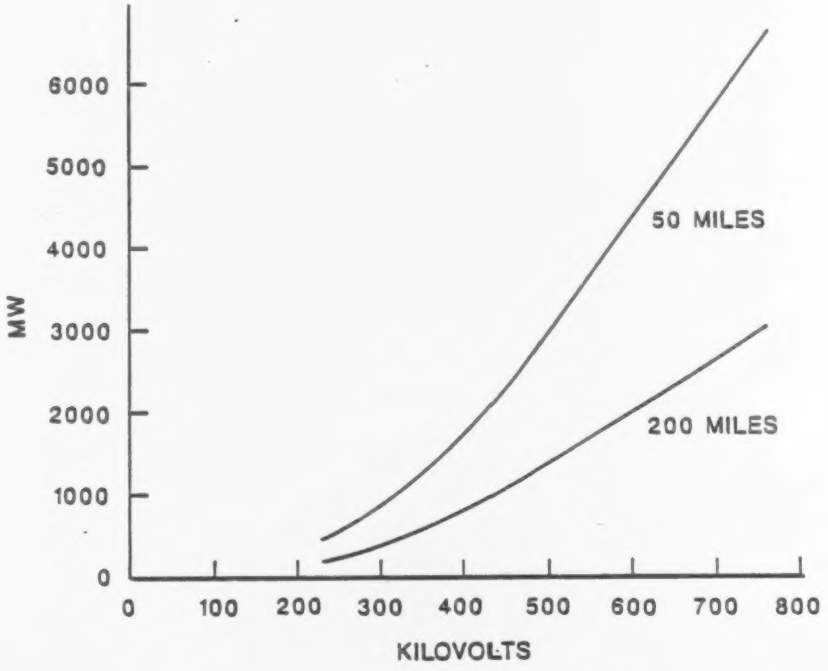


Figure 6.4 - Typical ac Overhead Transmission Capabilities Based on Surge Impedance Loading Concepts.

Figure 6.5 shows the approximate installed costs as a function of voltage for each distance. These were estimated using the cost data above and do not include costs for any additional VAR supplies that might be required. The costs for the 200 mile lines do not include any intermediate switching stations nor series capacitor compensations. These "typical" costs would be expected to vary widely depending upon the costs of rights-of-way.

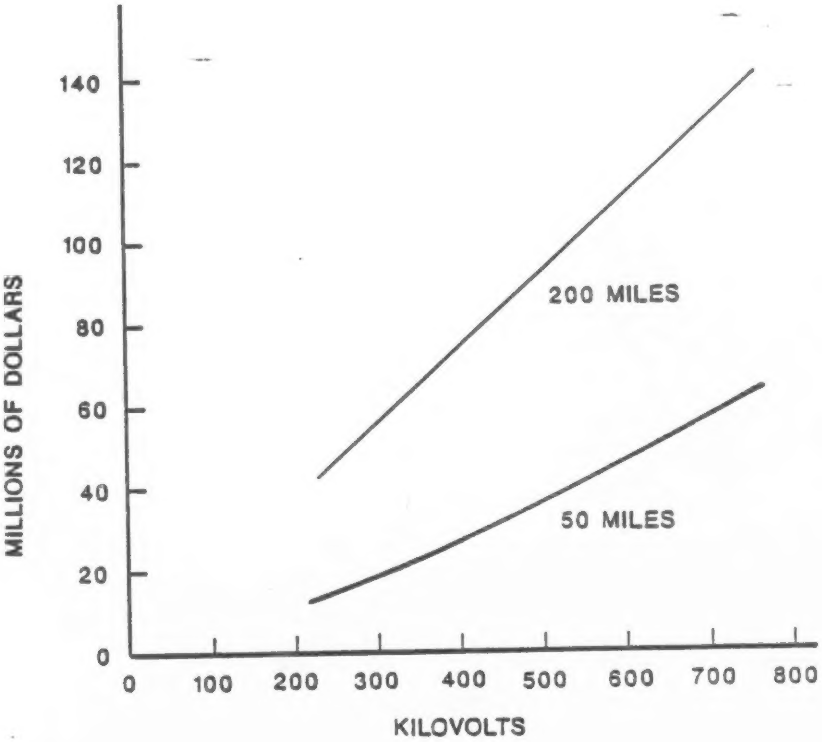


Figure 6.5 - Approximate Total Installed Coat of ac Transmission Circuits

The costs may be interpreted in terms of a capacity cost index, dollars per MW-mile by dividing the installed costs of Figure 6.5 by the respective line capabilities on Figure 6.4. The results, shown on Figure 6.6., demonstrate the decline in transmission capacity costs with ac line voltage level.

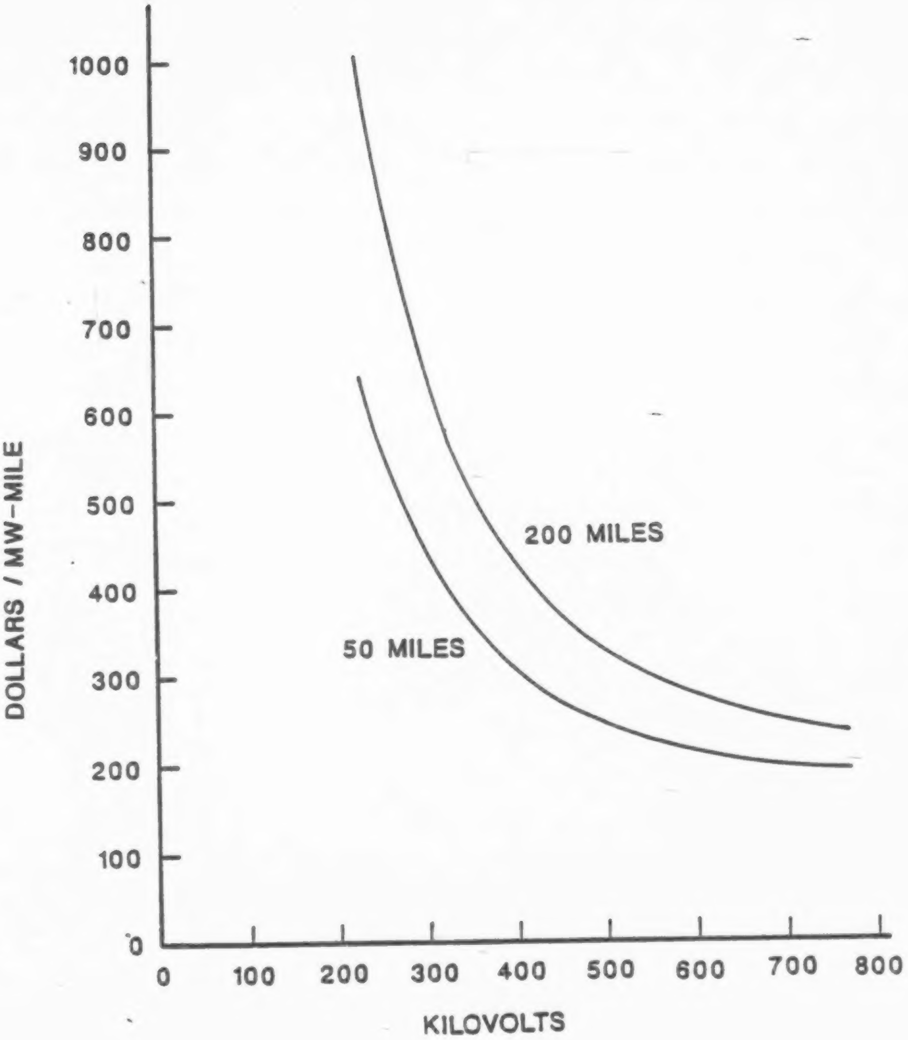


Figure 6.6 - Capacity Costs in Dollars per MW-mile for ac Transmission Circuits

CHAPTER 7

WHEELING AND NON-UTILITY GENERATION

7.1 INTRODUCTION

The previous Chapters provide a summary of the significant technical aspects of existing power systems and their operation that may restrict or limit the use of high voltage transmission systems. Technical remedies are available that may allow incremental increases in the capacities of existing transmission facilities. Major transmission capability increases require the building of new facilities or major reconstruction of existing circuits.

In the general review of wheeling and non-utility generation in this chapter it is assumed that the current industry structure remains basically as it exists today (January 1988) in order to review current and expected technical issues concerning wheeling and non-utility generation. Transmission access is presently generally limited to electric utilities and non-utility generators. Electric utilities are taken to include all types of utilities, those with generation, transmission and distribution as well as utilities which only distribute. Non-utility generation includes qualified facilities (QFs), cogenerators and independent power producers (IPPs). Dispersed generation sources (DSG's) are a subclass of non-utility generation, usually of smaller capacity and are connected to the system at distribution voltages.

Utilities' transmission systems have been designed primarily to deliver power from their own sources of generation to their customers with consideration given to economic interchange and generation reserve sharing. In power pools, power broker arrangements and where interchange transactions are arranged, the transmission systems are used to provide "wheeling". "Wheeling" between systems is accomplished by increasing generation in the selling system and simultaneously decreasing it in the purchasing system. The term "wheeling" has had many definitions. In this report the definition adopted is that given in the glossary appended to a recent report issued by the National Regulatory Research Institute [110].

> "Wheeling - The use of the transmission facilities of one system to transmit power of and for another entity or entities".

With this definition wheeling is another word for transmission, differentiated from it by the introduction of more than one entity.

In the current discussions over transmission access a variety of definitions of subclasses of wheeling have been used. For the purposes of this report, these are generalized as:

> "Wholesale wheeling - The wheeling of power and energy for delivery to a utility system".
>
> "Retail wheeling - The wheeling of power for delivery to a retail customer".

These definitions include existing or potential arrangements for the transmission of power generated by a utility or non-utility generator to a local or remote utility (wholesale wheeling) and the transmission of power from a remote utility, or a non-utility generator, regardless of location to a retail customer (retail wheeling.) The distinctions do affect the technical factors involved since retail wheeling would effectively remove the load from the local utility's service territory and the scheduled power transferred would become part of the scheduled net interchange used in the local utility's AGC system.

The growth of utility-to-utility wheeling, the prospect of mandated wheeling, and the increase in the non-utility generation sources plus the movement towards increased transmission access all pose a number of technical problems for the electric utilities. This chapter will discuss these technical problem areas and their relation to the current industry practices. The extension to consideration of specific forms of industry restructuring is taken up in the OTA report, "Technological Considerations in Proposed Scenarios for Increasing Competition in the Electric Utility Industry" [113].

Most wheeling arrangements under the current industry structure are made between essentially non-competing utilities. The wheeling of QF generation under PURPA provisions is the major exception. There is cooperation between utilities to support the operating integrity of the interconnections, to minimize inadvertent interchange and to allow each utility the opportunity to make the most economic arrangements possible. The current AGC designs and NERC operating guidelines reflect this cooperation. The introduction of mandatory wheeling requirements and competing non-utility generation resources complicates these voluntary arrangements. Competition between utilities may make this voluntary, mutual support less attractive from a local utility's economic viewpoint, but it does not remove the technical requirements to control the frequency by balancing the generation and demand.

The industry has always had some non-utility generation connected to the various networks. These have included industrial cogenerators who have made arrangements to sell excess power to the local utility and industrial firms which had internal generating plants to supply their own loads. With the energy crises of the early and mid 1970's there were additional independent generation sources developed to use renewable energy resources for both self-use and sale to the local system. The passage of PURPA in 1978 greatly accelerated the growth of non-utility generation. PURPA requires the local utilities to purchase the excess output of cogenerators and the output of qualifying facilities at the utility's "avoided costs" and to wheel this power to interconnected utilities if it cannot be absorbed locally.

The early cogenerators of any consequence on utility systems were mostly large chemical plants, oil refineries or food processing industries; industries with large process steam requirements. The generators installed were automatic steam extraction units where process steam is drawn from the turbine at the proper temperature and pressure for the industrial process. The plants were, and are normally operated in parallel with the local utility system and the industrial plant operators and utility system operators cooperated in the scheduling of the cogenerated power feed into the utility system. The type of generator used (i.e., automatic steam extraction units) allows the control of the electrical output over a wide range for a given steam demand. Therefore the steam demand cycle does not dictate the electrical output of the generator completely and the units are dispatchable by the system operators. More recent cogeneration plants have used combined cycle generators where the steam is generated using the exhaust from the combustion turbine [114]. In this type of cogeneration plant the electrical output is much more closely coupled to the demand for process steam. This is an essential difference and an important factor when considering the impact of new cogeneration on utility system operations since the electrical input to the local utility by a cogenerator using a combined cycle plant will be dictated primarily by the demand cycle for process steam and not the system's load demand cycle and marginal operating costs.

In small amounts, or with a few predictable large plants, non-utility generation does not generally cause major, unsolvable technical problems for the local utility. Smaller facilities, particularly dispersed sources of generation connected to the distribution system, will require more engineering assistance from the utility to ensure proper and safe operations. Larger facilities, particularly non-dispatchable generation blocks, may tend to tax the utility's capabilities for absorbing the power and delivering it to the loads. But as long as there are only a few such larger resources on a given system, the utility and non-utility generation firms' engineering staffs are usually able to develop mutually satisfactory means for handling the larger amounts of power. A large increase in the number of both small and large non-utility generators causes an increase in the technical problems for the utility since the amount of non-dispatchable power may seriously upset the normal scheduling of utility generation and thus restrict the capability to transmit power for normal and emergency purposes.

7.2 WHEELING

There are various forms that wheeling arrangements take under the present industry structure [29,115]. The most common application of the term involves the transmission of energy between two utility systems through the network of a third. This type of interchange is illustrated on Figure 7.1 where utility A is selling 1000 MW to C and the intervening system, B, is providing the wheeling. In this transfer the seller will increase his generation by 1000 MW and the purchaser will decrease generation by the same amount. The power will be transmitted through the network owned by B. Both loop flows and transmission system losses are ignored. Note that the wheeling system's (i.e., B) scheduled net interchange is unchanged by the wheeling transaction so total generation dispatched in B is for the same total demand that was prior to the transaction. The amount of wheeled power is usually fixed for a specified time period so the contribution of the wheeling transaction to inadvertent interchange is minimal.

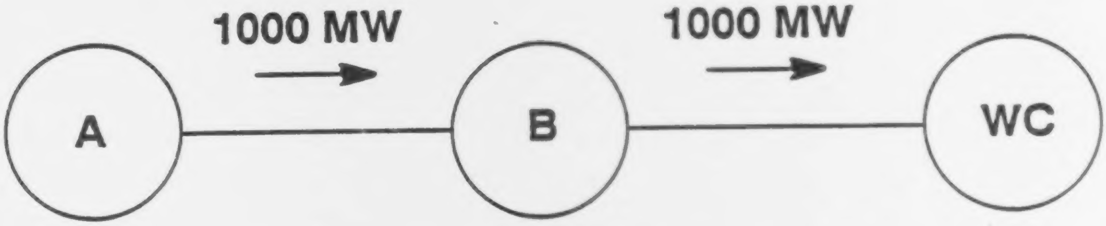


Figure 7.1 - Illustration of Inter-Utility Wheeling

The interchange agreement may take a variety of forms. System B may provide transmission service to A. Alternatively, the same result can be obtained by having two separate and simultaneous buy-sell transactions:

1. A sells 1000 MW to B
2. C purchases 1000 MW from B.

Broadly speaking, the results from a technical viewpoint are identical, 1000 MW flows from A to C via the network of system B. It has been common in the industry to refer to the first arrangement where transmission service is sold as wheeling. The second type of transaction is usually referred to as "displacement". This report will not make that distinction. It is of course important in matters involving transmission losses, VAR support for voltage control, rates, and wheeling charges.

Under the first arrangement it is fairly common that the seller provides the power which may be required to supply the added transmission losses in the wheeling system, B, due to the transfer. The purchasing system then receives the amount it contracted for. The wheeling system may have to alter its generation pattern and schedule of VAR resources in order to accommodate the wheeling transaction, so operating cost rates in the wheeling system, B, may change as a result of the transaction.

The wheeling transaction may increase or decrease the net power flows on the wheeler's transmission circuits. Power flows are characterized by both a magnitude and direction. An example of the potential effects of simultaneous power flows was shown in the previous illustration of loop flows.

Wheeling as defined here can involve only two parties under some circumstances. Take the case illustrated on Figure 7.2. There are two utilities involved that own a major plant jointly which is located in system B. When A, the co-owner of the plant, schedules generation from the plant, system B is wheeling the power to A. Another two party transaction that fits the wheeling definition adopted is that where a utility system transmits the power produced by a non-utility generator located in its service territory for delivery to the local utility's customers. This is wholesale wheeling. Wholesale wheeling of non-utility generation by the local utility for delivery to an interconnected utility involves three parties. The wheeling definition also encompasses the transmission of power and energy to another purchasing utility located within the boundaries of the geographic service area of a utility to meet the total or partial requirements of the load demand of the purchasing system. This is another common two party wheeling example. It is common to refer to this as a sale to a partial requirements customer, but it actually involves wholesale wheeling under the previous definition.

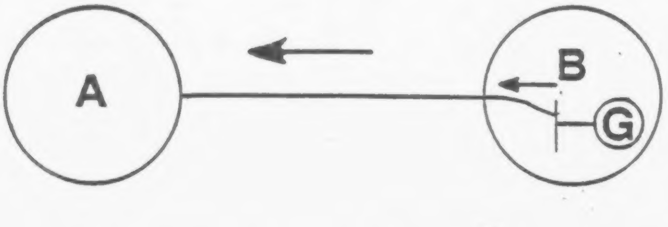


Figure 7.2 - Illustration of Wheeling of Power from a Jointly Owned Unit

The proposed retail wheeling arrangements that are being discussed currently involve the transmission of power to a retail customer where the power source is not the local utility, but another utility or a non-utility generator located within, or outside of, the local utility system. (This is sometimes referred to as "customer wheeling" instead of retail wheeling.)

Wheeling normally involves the utility's bulk power systems but some smaller non-utility generators may be directly connected to the distribution system. The connection of the DSG's to the distribution system involves a different class of technical problems and solutions than those due to the larger non-utility generators. These problems tend to be localized because of the distribution systems' configuration and the smaller capacity of the individual generators.

7.2.1 Technical Considerations in Wheeling

Wheeling transactions affect the utility in several technical and economic areas. These include:

- the determination of the wheeling capability,
- transmission system VAR requirements and losses, and
- system operation and planning.

Wheeling Capability and Technical-Economic Effects

When a utility dispatcher decides to undertake a wheeling transaction, he must determine the capacity available for the added transmission flows. Power flows are computed by use of digital computer load flow programs that compute the bus voltages, VAR requirements and power and VAR flows in the network for a fixed configuration of generation, load demands, and interchange schedule. The program contains data describing the electrical parameters of the network and information about conditions on interconnected systems. The results of the computation tell the engineers and operators the impact of new configurations. The system operators may carry this a step further and use extended versions of these models to tell them what might happen under worst case contingencies and in some installations, how to reschedule the generation to avoid the possibility of cascading failures (see the discussion in Chapter 3, Section 3.4.)

The decision to undertake any given wheeling transaction depends upon the current and expected conditions of the system. Wheeling arrangements may be made for as short as an hour or for very long periods. The capacity available on the transmission system for wheeling is not a fixed quantity but depends on the network status, distribution and level of load, generation dispatch, and other interchanges currently scheduled. If, for example, a proposed wheeling arrangement would tend to exceed available transmission capacity under one generation dispatch pattern, the system operator may be able to accommodate the new transaction by shifting generation. This would involve an economic penalty in the form of an increase in generation production costs. The operator must then balance the gains from whatever revenues the wheeling will generate against the added costs.

When utilities are involved in wheeling, the effects of simultaneous transfers must be recognized to determine the transfer capability limits. Because of power flow division and loop flows the available transfer capacity between any two areas depends on other transfers taking place. These capabilities are studied by utility engineers using load flow programs to consider the allowable boundaries of transfers. The results are frequently displayed using a transfer capability polygon diagram.

Figure 7.3 is the three area example of a transfer capability polygon used in Chapter 3 [40]. It is repeated here because of its relevance to wheeling and the transmission capability available for wheeling. The diagram shows how much power system X can transmit to system Y, considering the simultaneous transfers from X to Z. For instance, the Y to X transfer capability is 6200 MW when X to Z transfer is 5200 MW. On the other hand, if the transfers are in the opposite direction, with Z transmitting 2600 MW to X, X can only transmit 1300 MW to Y.

Three such diagrams are required to completely represent transfer capabilities for a three area (X, Y, and Z) system. Each diagram is valid for a specific operating condition (i.e., load and generation schedule) and an established reliability criteria (i.e., single or double contingencies.)

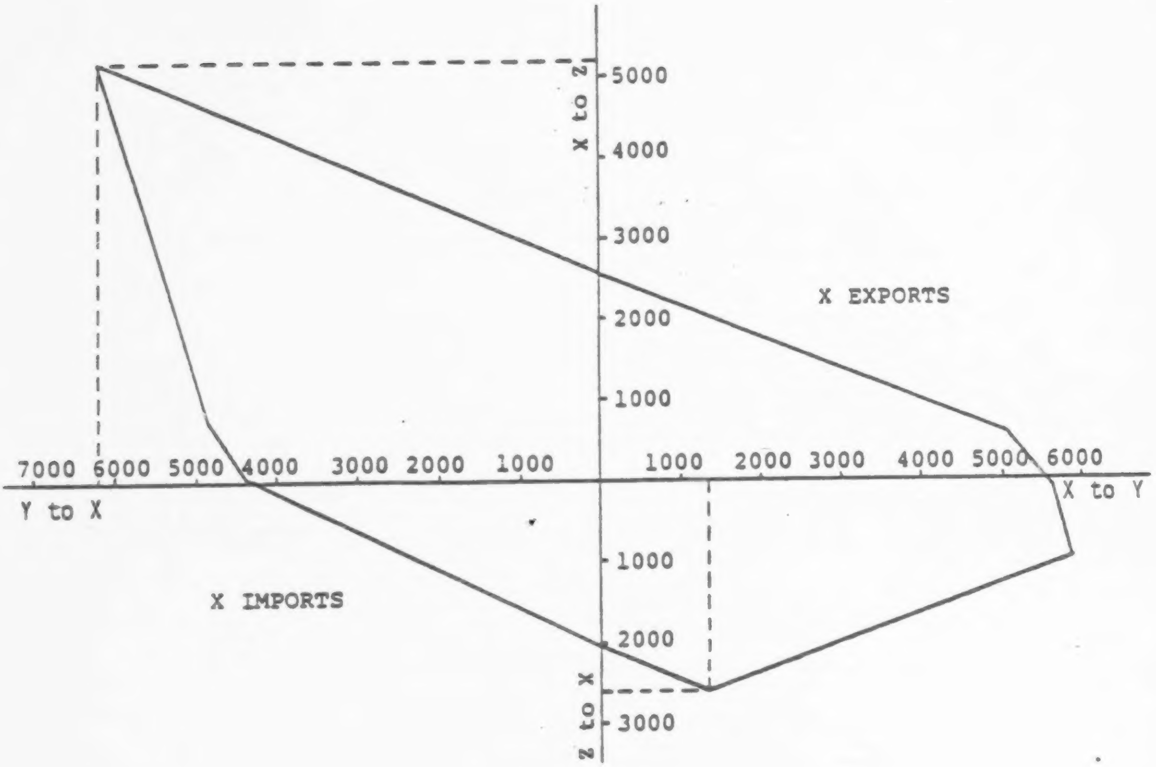


Figure 7.3 - Transfer Capability Polygon Example for 3 Areas
(Source: EPRI EL-3425) [40]

System operators know approximately how much these polygons change under different operating conditions, and control the system accordingly. Utility power systems engineers do not agree universally on how much power a network can transmit reliably under specific conditions. The state of the art is such that determining this requires fairly complex studies and application of engineering judgment.

If wheeling and transmission access increase (and particularly if utilities become more competitive and the incidence of retail wheeling grows), it will be important to measure a network's transfer capability in the short-term to schedule wheeling transactions. Buyers and sellers will need to know that they are being treated on a non-discriminatory basis and a utility providing wheeling services may have to demonstrate the equity of various operating decisions. New methods of analysis will have to be developed to do this.

These current methods are an accurate reflection of system engineers' concerns over system reliability and security. The utility engineers develop these limitations in cooperative studies and fully understand the techniques and implications of the results. The techniques are quite involved, however, and it may prove difficult to carry these procedures into an industry that has been restructured. The engineering judgements that form the basis for these techniques are inherently subjective and in the future the non-specialist may question the fairness and objectivity of these methods.

There is no simple analogy to the telephone system's "busy signal" on a power transmission network. The capability to wheel additional power on a system's transmission network is a function of the existing and expected flows, the pattern of load and generation on the system, the voltage profile and VAR support status, the reliability-security criteria used in determining the system schedule, and need for transmission system reserves. Loop flows and actions taken by the operators of interconnected systems influence the available transmission capability. A system may well have the thermal capacity for carrying additional transmission flows, but these incremental flows may jeopardize the system's security and utilize capacity needed to serve the system's own local load areas. The additional wheeling power to be scheduled, may cause loop flows on interconnected systems which use the capacity needed by these other systems to serve their own loads and the interchange transactions taking place simultaneously on other parts of the interconnection.

On the other hand, an incremental wheeling transaction may very well reduce the transmission system loading, release additional transmission capacity, improve the voltage profile and even reduce the wheeling system's operating cost rate.

Wheeling large blocks of power may also increase the operating costs of the wheeling utility by requiring additional generation to be placed online as spinning reserve. The selling system's input to the wheeling system looks like another large generation source. The NERC guidelines call for each area to supply its own spinning reserve requirements, but local conditions may dictate that the wheeling system needs to increase its spinning reserve in order to survive the sudden loss of the seller's input.

There is also no direct analogy in the electric power system to the telephone system's capability to switch traffic directly from a congested line to circuits with available capacity. When an electric power network is loaded to capacity, the remedial measures available to the operators to reduce the network loading on specific circuits are indirect, involving changing the generation pattern and possibly switching circuits to redirect flows where possible. Power systems may eventually have this control capability through the application of high power, high voltage electronic switching devices. That, however, is in the future.

Centrally dispatched power pools incorporate a special subclass of wheeling. In these pools wheeling takes place as a matter of regular operation where the more efficient, less costly generation resources are scheduled to supply loads throughout the pool. In these pools the arrangements are usually such that transmission charges, if any, are based on some agreed upon formula that essentially amounts to a rental charge paid by the other pool members to the owners of the major transmission facilities. Schedules are determined by the pool control center based on minimizing the operating costs to the pool members taken as a whole, without regard to transmission circuit ownership considerations.

Transmission System VAR Requirements and Losses

Wheeling flows may add or subtract to the power flows on major circuits. Where they increase the flows they will increase the power losses on the line and usually increase the VAR supply requirements. Again, the latter is not always the case.

Recall the concept of natural, or surge impedance, loading in an earlier section. When the power flow on a line equals its SIL rating, the VAR supply requirements are zero. Increasing the flow on a line originally below its SIL level may decrease the VAR requirements. Some wheeling transaction arrangements require the seller and possibly the purchasing utility to participate in the furnishing of the added voltage support.

Transmission losses on a given line will increase approximately in proportion to the square of the power flow. Figure 7.4 shows typical transmission line losses as a function of the power flow for a 100 mile long 345 kV circuit. A moderate increase in power flow may cause a disproportionate increase in power losses.

When more than one transaction is flowing on a given line in the same direction, it is a straightforward engineering computation to determine the total transmission loss. It is a matter of mutual agreement, however, to allocate the responsibility for the increased losses amongst the various flows. It is a common practice to allocate these losses based on the chronological order that the transactions were established. The immediate cost of losses to the wheeling utility is due to the increase in costs to supply the energy losses that accompany the power loss in the transmission line. Therefore the loading pattern (i.e., the load cycle pattern) of the transmission line flow is also important.

In systems that have extended transmission systems, incremental transmission system losses may cause shifts in the economic dispatch of the generation. Engineers have developed techniques to take the effects of losses into account when developing an economic dispatch. These methods may involve the development of what is known as a "loss formula" that relates the transmission losses to the power generation and the interchange power flows scheduled. The same purpose may be accomplished using "optimal load flow" models which is a scheduling program that includes the power network relationships as a set of constraints.

In an economic dispatch including losses, the marginal cost of power is not identical throughout the system. Rather, the system generation is balanced such that an incremental increase in generation anywhere on the system results in the same increase in production cost rate, including the effects due to the incremental increase in losses as well as the marginal cost of generation. Using these techniques, the marginal cost of power may be computed at various points in the network. These methods may be used to compute the marginal cost changes at various points in the network due to incremental power flows caused by wheeling transactions. Some utilities use these methods to develop the incremental cost of power at various delivery points in the network when these deliveries are involved in a wheeling transaction.

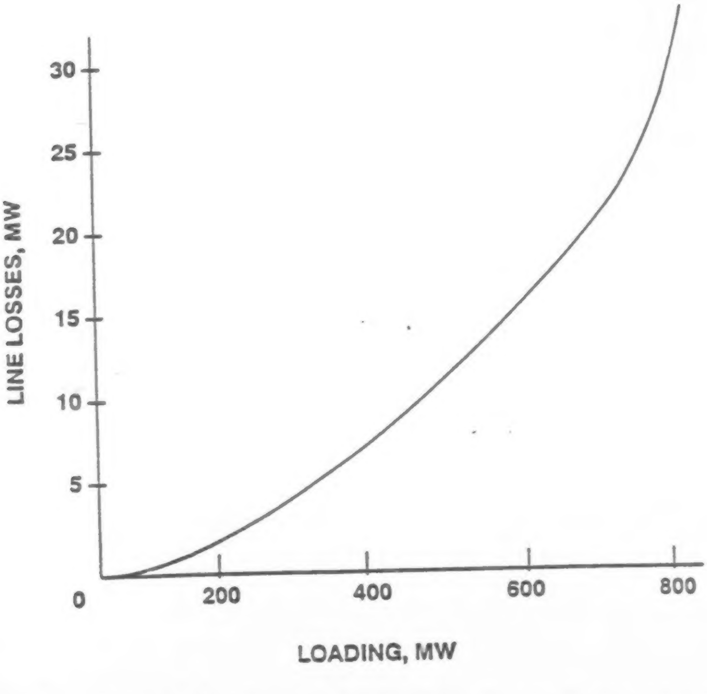


Figure 7.4 - Real Power Losses for Various Power Flows on a Typical 100 Mile Long, 345 kV Transmission Circuit

Effects of Wheeling on System Operation and Planning

Wheeling arrangements generally do not cause operating difficulties as long as there are a modest number of simultaneous transactions. These interchanges will be handled by the energy control center in the normal scheduling of the system's own generation. Utility AGC systems are designed to be operated with scheduled net interchange data supplied by the operators and actual interchange flows monitored on the system and transmitted to the AGC system.

The problem of allocating the transmission network is actually part of a larger problem. Scheduling generation (including maintenance), purchases, and sales needs to recognize the wheeling transaction options and effects, and vice versa. Today's economic dispatch techniques and programs work quite well, but they generally assume that the instantaneous optimization of generation leads to a generation pattern that is optimal over a month or a year. Utilities that face hydro or fuel constraints optimize schedules over a time horizon. Scheduling wheeling transactions, which can be as short as an hour or as long as several years, require optimization through time. Power system engineers will need to develop practical methods for optimizing this scheduling of generation and wheeling.

An increase in sheer volume of wheeling transactions and widespread transmission access will augment technical problems in other areas. If the number of non-utility generators' suppliers increases, if they are to be integrated into the AGC system, the telemetry into the utility control center will need to handle more distinct generators. This is not a theoretical problem, but every control center computer and communications system has limits on the amount of data it can handle. This may require the earlier replacement of the existing control center facilities.

If there are many wheeling transactions, especially wheeling transactions whose levels change frequently, the wheeling utility may have to train and add more personnel just to handle the interchange rescheduling. This has already happened to at least one utility in the United States, Houston Lighting and Power, which has had to add an energy scheduler to the dispatch staff. That utility estimates that over one-half his time is dedicated to handling the effects of cogeneration on system operations. The utility anticipates staffing about five additional people in the future to accomplish this function for all shifts.

With the present transmission network, a utility may be able to increase its capacity to wheel by relaxing the security criteria used to schedule the system. This is not a matter to be undertaken lightly, however, since reducing the preset practices may increase the incidence of cascading outages, system separations, and blackouts. This method for increasing wheeling capacity is also highly system specific. Each utility or area needs to consider the probable effects of a relaxation of security criteria. One suggested alternative is to substitute automatic corrective action after a contingency has occurred. For example, a generator that might have to reduce its output under security dispatch could be allowed to remain at its economically determined output level until such time as a specified contingency (or set of contingencies) occurred. The opening of a key line, for example, might be the automatic reduction of the plant's output level.

Another alternative that requires further research is to base operating security criteria on a probabilistic assessment of the consequences of application of various criteria. This would theoretically allow the development of operating security criteria based on a quantitative reliability standard rather than on the basis of the worst case philosophy currently used.

Difficulties in operation may arise if the number of wheeling transactions becomes large and if the flows deviate from those scheduled. With unpredictable transmission flows the AGC system will not have the correct data needed to discriminate between internal and external generation-demand mismatches. Generators may be required to increase their participation in regulation causing increased maintenance costs to the utility and increased levels of inadvertent interchange. Tie lines may become overloaded and tripped automatically.

The transaction costs of wheeling utility include the costs of monitoring the power flows, communicating these data to the control center, and preparing billing data for the transactions. Control center costs also involve staffing and computer costs for dispatching wheeling transactions. These costs are generally fairly low for normal inter-utility wheeling (i.e., wholesale wheeling), but will increase when the number of transactions and non-utility generators involved increases. The widespread introduction of retail wheeling would increase the transactions costs still further.

A large and unforeseen increase in wheeling transactions may also cause problems in the expansion planning of the entire system, but particularly the planning for the transmission system. If the demand for wheeling service is sustained and appears to be part of a long term growth pattern, system planners can take these added demands on the network into account when planning for system growth. If the wheeling requirements fluctuate and are characterized by a high degree of uncertainty, the planning engineers face a more difficult task. Part of their problem will be (and is in some systems now) the requirement to provide this transmission service while still maintaining service reliability standards in supplying the system's load. With shortages of transmission capacity there will have to be some form of rationing imposed by contract, price, auction processes, or direct control means. Before new facilities are constructed to handle the expected needs for increased wheeling transmission service, the stage will need to be set so that proper economic choices may be made by the utilities constructing these facilities. This is an area outside of the immediate scope of this report, but it impinges upon the planning engineering required to expand the network if, in fact, there is expected to be a need for these facilities.

In this regard there is a great deal of uncertainty today amongst utility planners concerning the magnitude, timing and reality of future non-utility generation sources. This uncertainty affects transmission planning as well since the non-utility generation must be transmitted (i.e., wheeling by the local system.) This same cycle may well be repeated because of the possibility of increased transmission access by non-utility parties, inter-utility competition and the possibility of expanded mandatory wholesale and retail wheeling.

7.3 NON-UTILITY GENERATION

Non-utility generation includes cogenerators, qualified facilities in the sense that PURPA uses, small power producers, independent power producers (IPPs) and distributed generation sources (DSG's). That is, it includes all generation not under the direct control of the utility where it is located. The distinction is deliberately made here between ownership and control. Ownership may affect planning in the utility in that plant size, type and availability may be different from utility owned capacity and the service life of a non-utility resource may be highly unpredictable. But the immediate key technical questions posed by non-utility generation center on the control of the generation. An IPP plant financed and owned by a non-utility entity, but operated and controlled by the local utility, would be no different technically than a plant owned by the utility. Generation plants that are operated by electric utilities under sale-lease back financing arrangements would have the same technical implications that they would have if they were utility owned.

The technical questions relating to wheeling are closely interrelated with the growth of non-utility generation. With the increased interest in non-utility generation the demand for wheeling service increases. Wheeling becomes a key requirement for the successful operation of non-utility generation unless the non-utility generator constructs a transmission system to deliver the power.

The technical areas principally affected by increased non-utility generation are:

- system planning, and
- system operations.

In addition there are different problems associated with dispersed generation. The technical problems associated with dispersed sources of generation (DSG's) have received a great deal of past attention. These non-utility generators are connected to the utility system at distribution system voltages and result in a different set of technical problems than the higher capacity cogenerators and proposed IPP plants.

The technical issues posed by the growth of DSG's are summarized below in Subsection 7.3.3.

7.3.1 Effects on Utility System Planning

One major effect that non-utility generation has on planning is caused by the great uncertainty that accompanies the growth of non-utility generation. Since 1978 and the passage of PURPA a large amount of non-utility generation capacity has been proposed. As fuel prices declined in the 1980's, a lot of this announced capacity has evaporated as utility operating costs and therefore "avoided cost" levels declined, reducing the potential economic rewards for construction of new non-utility generation.

This uncertainty continues. For example, according to their annual reports in 1986 Southern California Edison Company had contracts for about 3900 MW of non-utility generation. They published estimates that only 60% of this capacity would materialize. In 1987 3500 MW was still under contract, but the Company expected that only 1400 MW would actually be constructed. Situations like this make it difficult to plan the needed utility facilities to supply the transmission and generation needs of the area.

As another example, Figure 7.5 shows the published forecasts of non-utility generation issued by the WSCC region of NERC [116]. The data show the forecasts for the total generation expected to be in service in 1992, by year when the forecast was published, and the year-to-year variation in the forecast. The uncertainty is obviously quite large and presents an extremely difficult forecasting situation for planning staffs of the utilities. It requires several years of lead time to construct new transmission and generation facilities. If the non-utility generation actually does appear on the system, new transmission facilities may be required and the utility's own generation plans may be postponed. If the utility system construction is based on the early forecasts and the non-utility generating capacity actually does not appear, the utility may have transmission capacity that will not be fully required and face a potential generation shortage. On the other hand, if the planning engineers wait to see what non-utility generation is actually constructed, there may not be sufficient transmission capacity available to provide service to the new non-utility resource.

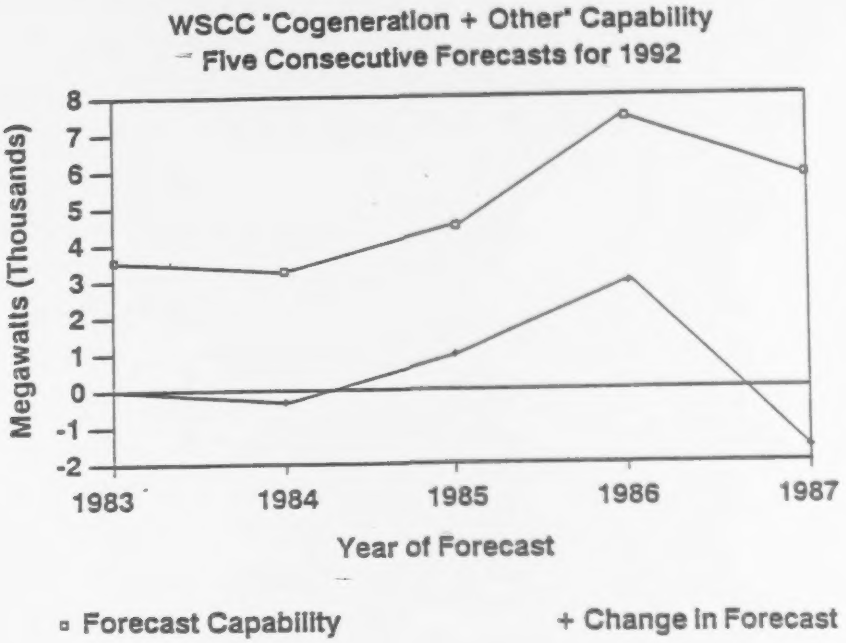


Figure 7.5 - Forecasts of Non-Utility Generation in WSCC. Upper Curve is total capacity forecast. Lower is year-to-year variation on the forecast.

Under today's conditions of high utility generation construction costs, moderate to high levels of generation installed reserves and high levels of interchange, it is likely that the construction of excess transmission capacity would be preferable, from the utility's viewpoint, over the construction of new utility owned generation facilities because of the difference in relative investment required and the added operating flexibility that may be obtained with the excess transmission capacity. The extra transmission may support increased economy and emergency interchange levels in the future and, if necessary, allow time for the construction of new utility generation. The utilities constructing this "excess" transmission run the risk that it may subsequently be viewed by regulatory agencies as not required and removed from the investment base allowed for purposes of earnings and rate regulation.

The potential effects of the uncertainty of actual future existence of the non-utility generation can be recognized in utility generation planning using probabilistic based reserve requirement planning techniques (i.e., the loss of load, or energy, probability methods). As a hypothetical example consider a system with a 2000 MW peak load. With its present generation mix and generation unavailability experience, the planning engineers calculate a loss of load probability of 1.27 days per year for a generation reserve level of 20% of the expected peak load using their generation reserve calculation methods based on loss of load probabilistics.

Two alternatives are considered, (1) adding a 300 MW utility unit with a 10% unavailability or (2) by the utility planners adding four 75 MW non-utility generators which may be constructed. These are each expected to have an unavailability rate of 10%. At the time the planning takes place there is only a 50% probability that they will be constructed.

The reliability assessments of these two alternatives using loss of load probability methods shows that the additional 300 MW of utility capacity will support a 214 MW growth in peak load at the present reliability level, while the four 75 MW non-utility generators will allow only a load growth of 107 MW with the same expected generation system reliability. To achieve essentially the same load carrying capacity at the existing calculated reliability level would require about seven 75 MW non-utility generators assuming the similar accepted, unavailability forecasts. The differences are due solely to the differences in the expected availability of the future capacities caused by the current belief that there is only a 50% probability that the non-utility generation will be constructed.

These are, of course, planning data based upon current perceptions of the future. But they illustrate the utility generation planners' dilemma. With current experience based on the actual realization of non-utility generation, overall future generation reserve requirements increase in order to hold current, generation reliability levels. The effect is due entirely to the expectation that half of the announced (i.e., "planned") non-utility generation will not be constructed.

If the utility proceeds with its own construction plans for the 300 MW unit and the non-utility generation is constructed, the installed reserve levels may be uneconomic. What appears to be required is some procedure similar to the current bidding system for non-utility generation used in some states to secure new capacity coupled with a system for ensuring that accepted bids are actually carried out.

Another planning uncertainty caused by the growth of non-utility generation has to do with the longevity of these plants. For example, cogenerators are tied to the need for process steam which in turn is tied to the market place for the particular product being manufactured. Utility planning engineering determinations are generally based on the expectation that generation plants will have average service lives of 30 years or so. A cogeneration plant may disappear from the scene just as rapidly as it appeared. If the local utility has counted on this as a dependable resource and it vanishes, they may be forced to make an expensive substitution.

The potential effects of this particular uncertainty are in the same order of magnitude as that which the utility faces with major industrial customers. The longevity of these firms and the requirements for serving their loads are just as volatile as the generation supply of the cogenerators. The essential difference between these situations is that if a major industrial customer leaves the system, the utility is left with an excess capacity as well as a loss of revenue. If an industrial cogenerator leaves the system, the utility may be left with a shortage of generation capacity that will have to be made up by purchases, the advancement of the next plant to be constructed, or the construction of a gas turbine plant.

Non-utility generators may benefit technically from careful cooperation and coordination with the local utility engineering staff. The early notification of the intent to bring a new facility online will allow the combined engineering coordination required to achieve the lowest cost solutions to specific, local technical problems and the development of joint operating practices and installations to protect both the utility facilities and the generation in the new plant. Studies should be made of circuit breaker short circuit duty requirements, protective systems for the new plant, and operating procedures in case of system or non-utility generator emergencies. Arrangements for backup supplies and emergency supplies should be established appropriate to the specific situation. An industrial cogenerator or IPP may have the capability of supplying VARs for voltage support at weak points in the network.

7.3.2 Effects on System Operations

The effects on utility system operations of non-utility generation depend upon the number, relative sizes, locations, and dispatchability of the facilities. A large number of small sources located near load centers could unload the transmission network, easing the scheduling problems. Smaller facilities such as wind generators would probably be uncontrolled resources insofar as scheduling the utility generation is concerned and are usually connected to the system at distribution voltage levels. As long as the total generating capacity of these uncontrolled sources is relatively small (e.g., less than 3 to 4%) with respect to total demand, these would pose no more of a regulation problem than that faced now by the utility in the uncertainties associated with forecasting load. Certainly the variability and uncertainty of these resources would add to the total uncertainty faced by system operators so that levels of spinning reserve might need to be increased. In some systems where non-dispatchable DSGs are connected to the distribution system, the system operators may treat these resources as load reductions.

Large cogenerating plants, plants burning collected refuse, and plants burning waste products generated by an industrial firm, may have to be operated to serve the demand for steam and the need to consume required amounts of refuse, wood chips etc., on a given time schedule. As such, their electrical outputs may follow a different cyclical pattern than that of the system load demand. This would require the system operators to consider these plants as "must run" units in dispatching the system. If wheeling is required to deliver the output to utility load centers, this would also have to be taken into account. The utility may be providing backup service in case of a cogenerator plant outage so that the utility system operators will then need to increase the available spinning reserve levels to accommodate the possibility of a sudden plant outage. This increases load uncertainty effects in system operation.

The degree of dispatchability and interruptability of the larger capacity, non-utility generators may seriously affect the economic scheduling of the utility's own generators. The utility's own dispatch must be adjusted to accommodate this power delivery, requiring that the non-utility generation be monitored and the data transmitted to the utility control center.

The amount of difficulty this may cause and the resulting increase in utility generation operating costs depends, to a great extent, on the amount of non-utility generation relative to the system demands. The light load periods may cause particularly severe operating problems to the utility if the amount of non-dispatchable non-utility generation capacity online approaches the level where it represents a substantial fraction of the minimum system load level. These light load period load levels vary from system to system and are usually in the order of 30% to 50% of the daily peak load. They occur in U.S. systems generally in the early morning hours between midnight and 6:00 a.m.

The reasons for the scheduling problems during light load periods are related to the utility's generation mix and the operating characteristics of various types of large steam turbine generators. Many utilities have installed larger, base loaded steam turbine units with reheat cycles, some incorporating supercritical steam conditions. Most of these units are very efficient and very few of them are designed to be operated in a cycling mode where they supply varying outputs, or for two shift operation where they are taken off line for the light load period of the day. Most of the modern, larger size steam turbine generator units are not designed to be operated below output levels of 25% to as much as 40% of their maximum capacities.

The utility must operate sufficient capacity to provide the required regulation and to guard against sudden capacity shortages, even during light load periods.

Therefore, with a large amount of non-utility generation being delivered to the system during light load periods, the system operators must devise unit commitment patterns and economic dispatch schedules which allow them to satisfy all of the system requirements and unit constraints.

If the system is operated without capacity sufficient for the adequate control of frequency and voltage, inadvertent interchange levels will increase and voltage levels may get out of their normal ranges. In an extreme situation of this type it is quite possible that the system may be isolated by its interconnected neighbors and even be forced to shut down due to under and over frequency relaying systems.

When non-dispatchable non-utility resources approach 25% to 75% of minimum load demands, the system operators may have to cycle their most efficient plants off for several days at a time to avoid undue thermal cycling of the units and run smaller, less efficient plants to provide the utility capacity needed to supply loads, control frequency and voltage levels and handle emergencies. The schedules that are feasible may be far from the most economic to satisfy the load since smaller units, capable of providing the required regulation and capable of two shift operation, will have to be run.

There are several technical and economic (or "contractual") methods to alleviate the problem. One is to require a certain amount of utility control over the dispatch and operation of the non-utility generation, incorporating mutually satisfactory terms in the agreement between the utility and the non-utility entities. If a large per cent of the utility generation is in units that cannot be cycled to low enough output levels or shut down overnight, the machines may have to be modified to permit this type of operation. This is feasible in some types of steam units but is usually expensive. It is not considered to be feasible for nuclear units operated by U.S. utilities.

Small amounts of non-utility generation may be considered to be load reductions by the utility dispatchers. Larger, non-dispatchable units will be treated as must-run capacity. Utility operators would prefer to have all larger non-utility generation dispatchable, and in fact with proper contractual terms, this may be best for some non-utility operators as well. The dispatch of non-utility generation might be based on fixed or time differentiated prices for the non-utility energy or the utility's and non-utility generators' marginal operating costs. If the utility is required to modify existing plants to provide the proper type of light load capacity, questions concerning the responsibility for the expenses are certain to enter into any agreements for payments for the non-utility generation.

Non-utility generators may be located on the system at points where poor voltage control exists. It may be necessary for the utility to require that power factor excitation control systems be installed on the generator to avoid local high voltages or to allow unmanned operation of the generation. These control systems set the level of VAR generation. In turn these regulators may limit the VAR support that a non-utility generator may supply in supporting voltage limited systems.

The utility system operators and planners must consider the effect of the non-utility generators on system transmission network loading and dynamic problems. In particular locations on systems with long lines, the non-utility generators may require the curtailment or rescheduling of utility generator operation to alleviate local transmission bottlenecks caused by wheeling requirements. This may remove generators that would otherwise contribute to system stability.

Non-utility generation that has a highly variable output may contribute to the system's area control error, causing excessive regulating action by the utility's generation and increasing the inadvertent interchange. This is, of course, highly dependent on the total MW of this type of generation on the system.

A more frequent operating problem is that of coordinating the non-utility generation with the system actions during emergencies. Typically, a non-utility generator will be connected to the utility transmission system at subtransmission or even lower voltage levels. Underfrequency relays are frequently installed to trip the non-utility generation when it becomes islanded with utility load. This serves to protect the generator from the harmful effects of sustained underfrequency operation and prevents backfeed, the unexpected energization of the system, with its attendant possibility of high voltages or safety problems. This same underfrequency relating practice, however, trips the non-utility generation when there is an area-wide generation shortage, further increasing the area's total generation shortage. To guard against this, the utility may have to increase its spinning reserves. A better practice would be to coordinate the emergency operation of the larger sized, non-utility generation with that of the utility's own generation. Perhaps larger non-utility generators could be connected to the system at transmission voltage levels. Area loads in the local district containing the non-utility generation might have their own separate underfrequency relaying scheme so that the non-utility generation would not be tripped except under certain islanding conditions. Even then it might be better, in some instances, to leave the non-utility generator online to attempt to balance the local load with the non-utility generation capability to avoid a complete blackout of the islanded area.

Very large capacity plants that may be owned and operated by an IPP present another, but similar, set of operating problems. It may well be that the plant's output under normal conditions is not subject to regulating duty under the control of the utility operating center's AGC system. That is, it is supplying power at a fixed level to the system. Certainly the output would be monitored by the control center and arrangements would need to be made concerning the participation of the IPP plant in voltage support-VAR supply duty. A large IPP plant would undoubtedly be controlled by a capable operating staff with engineering support, and if there is close communication with the utility control center, there should be no unusual demands placed on the utility to provide additional spinning reserves.

Emergency operation and planning will require close coordination and cooperation between a large sized IPP and the local utility. It would seem in everyone's best interests to facilitate this. When the system is shut down for a prolonged emergency, the IPP is out of business. The cooperation to avoid emergencies and to restore the system as rapidly as possible after one does occur would maximize the IPP's revenues related to energy production and improve the overall utility performance.

7.3.3 Disbursed Generation Sources

The technical literature has discussed many aspects of the growth of DSG plants on utility system planning and operation. (See, for example, a recent summary in Reference 117.) Many technical problem areas of the relatively small sized DSG's are due to the combined effects of the operating characteristics of these plants and the fact that they are usually connected to the utility network at distribution voltage levels [117 - 120]. Utility distribution systems were not designed to handle local generation, but were intended to serve only for the delivery of energy to retail customers. The voltage control devices (i.e., automatic voltage regulators and switched capacitors) and protective systems (i.e., relays and circuit breakers) on the distribution system were installed to control voltages and protect the system and customer installations assuming power flows from the substations to the retail customers and relatively low short circuit currents under fault conditions. The installation of generation this far "out" in the system creates potential situations that were not intended in the original system layout.

These DSG plants may use synchronous generators where excitation of the machine is supplied separately. Some may use induction generators that must be separately excited, either by a VAR supply transmitted from the system or by a separate installation of capacitors to supply the required excitation. The DSG's may contribute to voltage control problems and the short circuit interrupting duty of the circuit breakers, fuses and circuit cut-outs on the distribution system. Other DSG's such as photovoltaic units generate dc power that is changed to ac with static invertors. These devices may generate harmonic currents and voltages that appear on the distribution system.

Technical problems that have been cited include:

- neutral shift for some types of connections of three phase transformers,
- harmonic voltage and current generation where static invertors are used to change the dc DSG output to ac,
- voltage flicker on the distribution system,
- problems due to the reclosing of DSG units after fault removal that may cause damage to DSG units,
- induction generators that may self-excite causing voltage problems,
- resonant overvoltage conditions,

- lines and transformers loaded to levels beyond their capacities requiring reconstruction of lines and transformer changes,
- capacitors installed for power factor correction causing self-excitation of generators resulting in voltage problems on the system, and
- safety problems frequently associated with backfeeding the system when a load area containing DSG(s) is isolated.

The DSG related problem areas are particular to each location and system. Some will occur with some types of distribution system layout and particular DSG plants. Others may never occur or may occur in unexpected places in the system.

These problems normally have satisfactory technical solutions. The utilities have generally worked out minimum standards for the connection of smaller non-utility sources that are not unduly restrictive. Many of these standards will require the DSG owner to install protective systems that are intended to prevent damage to the DSG as well as minimize potential problems with system operation and safety. There does not seem to be any general movement on the part of electric utilities to prohibit the connection of non-utility generation as there was in the past when telephone companies initially made it difficult to connect "non-standard" (i.e., utility supplied) equipment to the system. Rather, the electric utilities appear to be establishing reasonable standards that will ensure the protection and safe operating practices of both the DSG plant and the system.

7.4 WHEELING OF NON-UTILITY GENERATION

The wheeling of non-utility generation may be wholesale wheeling, transmission of the power and energy to the local utility, or another utility, for ultimate delivery by the utility to retail customers. The local utility must meter the output of the plant and for larger supplies, transmit these data to the operating control center in real time for use in the utility generation dispatching and AGC systems. This increases the number of metering points and data transmission requirements. For wheeling to another utility, the interchange levels may fluctuate if the non-utility generation level is not constant or on a fixed schedule.

Figures 7.6 and 7.7 illustrate the wholesale wheeling situations where a large non-utility generator, "G" is delivering power to the local utility or an interconnected utility. In the first case on Figure 7.6 the non-dispatchable generation may be considered as must run capacity by the local system operators. In the second case shown on Figure 7.7, the wheeling transaction is treated as a scheduled interchange transaction by the operators of both utility systems.

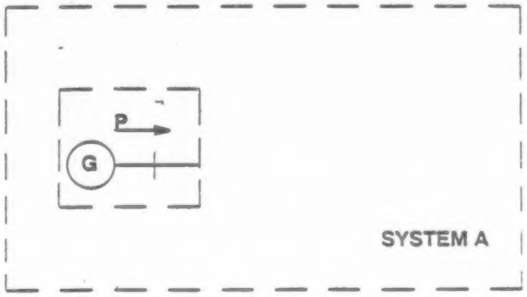


Figure 7.6 - Wholesale wheeling of P MWs between a non-utility generator G and the local utility system A. Non-utility generation considered as a must-run unit for scheduling A.

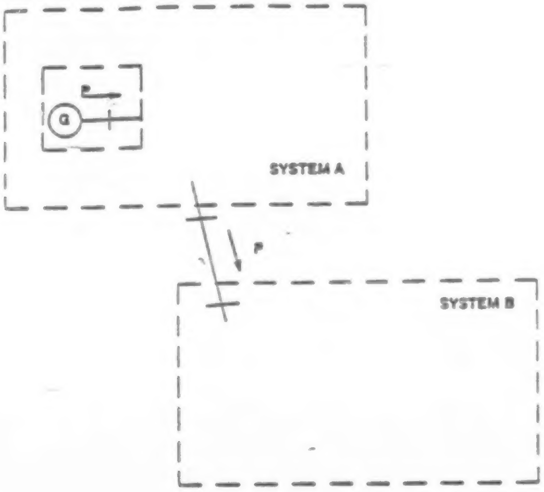


Figure 7.7 - Wholesale wheeling of P MWs between a non-utility generator G located in utility system A and an interconnected utility, system B. Treated as a scheduled interchange by both systems. In the scheduling of A it is between the generator, G, and system B: in system B it is between the two utility systems.

The requirement for wholesale wheeling may increase or decrease transmission system loading depending on the location of the non-utility resources and the prevailing power flow patterns on the system. In some utility systems new non-utility generation has been located where the added power flows contribute to the loading of critical transmission circuits or transformers causing transmission bottlenecks. This may restrict the utility's abilities to dispatch the system economically, to carry out economic interchange transactions, or to import emergency energy in case of area shortages. The remedies are not always apparent and have required suggested schemes for (or the imposition of) some form of rationing of the available transmission capacity. Rate structures and time and load dependent wheeling rates have been suggested as have auctions of available transmission capacity for wheeling.

The long run cure for these transmission capacity shortage problems is the construction of new transmission capacity by rebuilding existing circuits or installing new circuits. These are relatively expensive remedies and in some localities may prove extremely difficult. One planning problem that arises is due to the relative lengths of the time periods for planning and constructing transmission versus that for building new non-utility generation. The permitting, licensing, land acquisition and construction cycle for transmission can be quite long (e.g., several years). It is usually much longer than that required to construct a combined cycle cogeneration plant, for example. If the utility does not have sufficient lead time, the needed transmission capacity may not be available when the cogenerator is ready to deliver power. The planning for the needed transmission facilities needs to be coordinated with the plans for the non-utility generation as soon as possible. The real cure for this problem is probably to find some acceptable means for speeding up the licensing, permitting, and construction cycle for new transmission.

The introduction of retailing wheeling of non-utility generation introduces added technical complications. When the generation is to be wheeled to a retail customer, theoretically the generation-load combination is no longer part of the utility's area of responsibility for balancing the load and generation. Larger amounts of non-utility generation delivered from one plant to a retail customer would have to be monitored at both source and delivery points to provide data for the utility AGC system. Figure 7.8 illustrates this situation. If the generation and load demand are not balanced at all times, the utility's inadvertent interchange will increase. If the incidence of non-utility generation being wheeled to retail customers increases, causing an unacceptable level of inadvertent interchange, the arrangements between the parties may have to be altered so that the utility's AGC system treats the non-utility generation sources and the loads being served as part of the utility's responsibilities and it supplies any mismatches that may occur. This may lead to some form of rate structure for providing this needed regulating duty that would motivate the non-utility generator to install the equivalent of an AGC system for control of its generation. Again, this is not an insurmountable technical problem. It does require that the utility install additional monitoring and data transmission for the generation control.

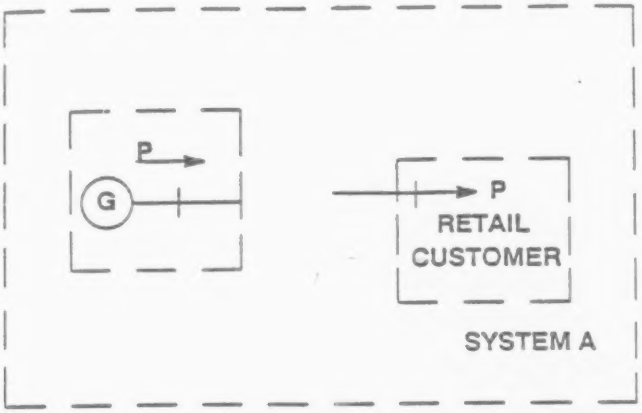


Figure 7.8 - Retail wheeling of P MWs between a non-utility generator, G, and retail customer both located in the same utility area. Treated by system A dispatch and AGC as a scheduled interchange between G and the retail customer. If there is a mismatch between the non-utility generation and retail customer demand, other interconnected systems will consider it is caused by system A and they will not be able to discriminate between system A and the retail wheeling within system A.

The special case where a non-utility generation source wishes to wheel power over the utility network to serve the loads in a remote facility belonging to the same organization is no different from the general case of retail wheeling between a non-utility generator and any other load in the same utility system.

Retail wheeling to a customer located in one utility system from a source located in another system is a different case, however. In this situation, shown on Figure 7.9, a non-utility source in system A is selling power to a retail customer in system B. The generation is no longer a controlled resource of utility system A and the AGC system of system A would treat the wheeling as a scheduled interchange between system B and the non-utility generator, G. The retail customer load in system B is no longer a part of its load responsibility, so that the AGC system in B would treat the wheeling transaction as scheduled interchange between A and the retail customer. In theory this is straightforward. However, if the load and generation involved in the retail wheeling transaction are not balanced at each moment in time, the inadvertent interchange levels will rise and the utility systems may be required to perform additional regulation to control frequency.

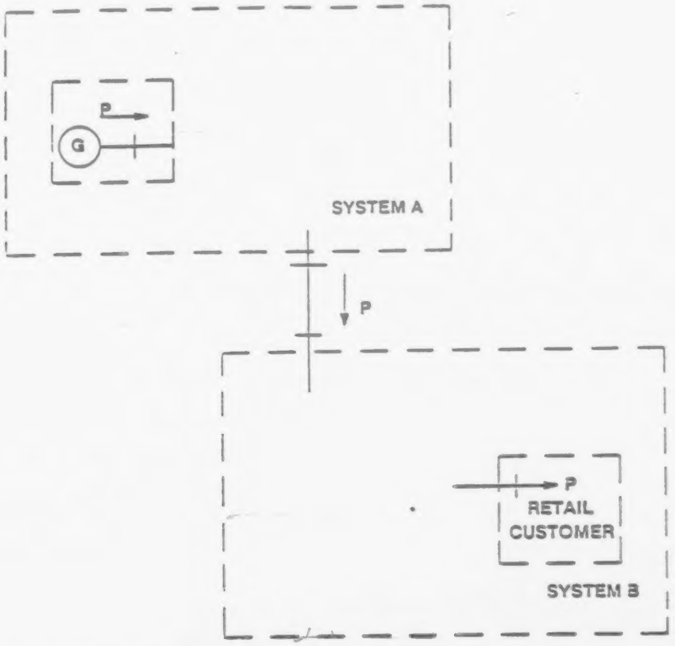


Figure 7.9 - Retail wheeling between a non-utility generator, G, located in system A and a retail customer located in system B. For scheduling and AGC purposes system A treats this as a scheduled interchange between G and system B and B treats it as an interchange scheduled between system A and the retail customer. For a fixed generator output level, P, and a variable load of the retail customer system A controls will assume the mismatch is in system B.

This is a similar situation to the one discussed previously, except that it now becomes evident that some sort of augmented or modified AGC systems will be needed if retail wheeling serves a significant part of the system load. Without the imposition of some form of control on the generation sources and retail customer load demands involved in retail wheeling, the responsibility for load-generation balance becomes less well defined. The generation source may be delivering a fixed amount of power to a cyclical load. The load is no longer (under the assumptions made for discussion) the responsibility of the local utility, but is the responsibility of the generating source. If retail wheeling is to take place on any sizable scale, these control matters will have to be settled. Perhaps agreements may be made such that the local utility containing the retail load provides the regulation needed to handle the retail wheeling of a fixed amount of generation to a cyclical load demand. (That is, it acts in a manner similar to a flywheel.) The costs for this arrangement versus the costs for the installation of a special AGC system control system for the generation source could then be used by the non-utility generator to select the most economic alternative.

7.5 A CAVEAT

Although this chapter contains an optimistic view of the accommodation between non-utility generators and their need for added wheeling services, the unconstrained connection and operation of non-utility generation to transmission and distribution systems could lead to chaos. The present interconnected power systems work, and work well, because the generation control systems keep the generation and demand closely balanced. If a large portion of the system generation becomes uncontrollable in the sense that it does not contribute to system regulation and is excluded from control by the utility system's control center, current economic scheduling and AGC systems may require major revisions. Similarly, the large interconnections that exist today, operate successfully, permit large amounts of economy interchange to take place, and minimize frequency excursions. They work because of the close frequency tolerance (i.e., load-generation balance) that is maintained and the voluntary cooperation of the interconnected systems' operators.

A general rise of unscheduled interchange power levels could use transmission capacity already scheduled by a utility. In the extreme it could result in the frequent overloading and opening of key interconnection circuits. If inadvertent interchange energy becomes very large, the present scheme of making payment in kind (i.e. returning MWh for MWh at similar times of the load cycle) may have to be replaced by additional metering systems and billing systems along with appropriate tariff structures.

If the future growth of non-utility generation is such that each independent operator of non-utility generation is permitted to attempt to operate to maximize his output, a revision of the economic scheduling and AGC methods may be required. Regulating duties imposed on utility controlled generators would increase and a new, more stringently enforced set of operating rules might be required to preserve the widespread interconnected operation of today's systems.

CHAPTER VIII

CHAPTER 8
SUMMARY

8.1 GENERAL BACKGROUND

The purpose of this report is to present an overview of some of the important technical aspects of the U.S. electric utility industry and relate these technical factors to questions regarding:

- transmission system technical limitations,
- non-utility generation,
- increased possibilities for wheeling, and
- increased transmission access.

The industry is extremely diverse, with utilities ranging from large integrated holding companies which operate in several states to small distribution utilities serving a local community. The diversity is a result of the differences resulting from the historical evolvement of the systems, the nature of the loads, and the availability of various types of resources for the generation of electric energy. The institutional structure includes an equally wide spectrum from large investor owned holding companies and large state or federal power agencies to small consumer owned cooperatives.

1. The industry is extremely diverse.

The systems are all operated to produce energy at a standard frequency of 60 Hz which is delivered to the retail customers at utilization voltages that must

2. The systems are all operated to produce energy at a standard frequency at voltages that must fall within narrow, standardized limits.

fall within narrow, standardized limits. These standards have been essential to the growth of the industry. Practically all electrical devices (i.e., motors, lamps, electronic devices, etc.) are designed and constructed to operate correctly only within the very narrow standards that apply to voltage and frequency.

An important attribute of electrical energy is its reliability. Although not subject to formal engineering standards, a high reliability of service is a de facto standard in the industry. Consumers have received a high level of service reliability and the industry strives to continue to deliver their product on a very reliable basis. The reliability benefits both the consumers and the utilities. Widespread and prolonged service interruptions may cause consumers discomfort and economic losses. In some situations the loss of power may be life threatening. The consequences of poor service reliability to the industry itself are economic. Widespread, prolonged outages are expensive to remedy and may expose the utility to subsequent economic penalties.

3. A high level of service reliability is a de facto standard in the industry.

Electric energy is a unique product in a very important technical sense. It is consumed at essentially the same instant that it is produced. Except for the storage of water in hydroelectric plant reservoirs, there is no storage of the product; no way of building an "inventory" for later consumption.

4. Electric energy is a unique product in a very important technical sense. It is consumed at essentially the same instant it is produced.

The delivery system (i.e., the transmission and distribution systems) also has unique technical characteristics that make it different from telephone, gas or transportation systems. The flow of electric power must obey the physical laws that govern its behavior at all times. Power flow patterns will be instantly and automatically redistributed when demands change, generation patterns change, or when the transmission system is altered due to a circuit being switched in or out of service.

5. The flow of electric power must obey the physical laws that govern its behavior at all times.

There is no simple way, in an ac transmission system, to control the redistribution of power flows from a heavily load circuit to one with a light load. Power flows are controlled normally be shifting generation patterns, switching circuits, or dropping customer loads. The power system does not enjoy the same ability as that of the telephone system where communications may be switched automatically from a busy trunk line to a line with spare capacity.

6. The power system does not enjoy the same abilities as the telephone system to switch flows from busy circuits to circuits with spare capacity.

The industry is quite large with about 100 million customers being served by over 700,000 MW of generation. The vast majority (98 to 99 % approximately) of the generating capability is owned and operated by the utility industry. Hydroelectric and nuclear power plants, each comprise about one eighth of the total capacity with the remainder being fossil fueled steam and combustion turbine capacity. The transmission system is equally diverse and large with about 610,000 miles of circuits at voltages of 22 kV and above.

The systems in the U.S. and Canada are interconnected in four large groups. In each of

7. The systems in the U.S. and Canada are interconnected in four large groups.

these the frequency is the same and power may theoretically flow throughout each interconnected area. The four groups, known as interconnections, are located in the western states and western Canada, the eastern states and parts of eastern Canada, the province of Quebec and the state of Texas. The interconnections are tied together by dc circuits of limited capability which allow the control of the power flows between the larger systems. The reasons for the separation are historical, demographic and electrical. The eastern and western systems are separated by areas with low population and electrical load densities. The system in Quebec is very difficult to control during emergencies because of the very large concentrations of remotely located hydroelectric capacity and the many systems within the state of Texas have long had a preference to remain electrically isolated from the other interconnections.

The pattern of transmission systems that exists reflects the development of each region. In some areas there are extensive high voltage and extra high voltage systems that integrate large systems and permit the exchange of economy energy over long distances. In other regions, the pattern of development has been such that generation resources could be located close to load centers with the result that less transmission has been required.

The technology of high voltage ac transmission is such that the capability to transmit electric power of individual classes of circuits varies approximately with the square of the nominal voltage level for a given transmission distance. The capability of transmission circuits also varies with transmission distance: a shorter line is capable of carrying more power than a longer one, all other things being equal. Longer line capabilities are limited by technical problems associated with the stability of the system while shorter circuits are usually limited by voltage related problems and the required VAR support.

VARs are analogous to MWs in the sense that they will flow in an ac electric power circuit. These are a consequence of the inherent physical nature of ac circuits where energy is stored in electric and magnetic fields. VARs are required to support these fields and the fields are essential to the operation of the ac systems and consumption devices. The quantity of VARs required depends on the needs to control the voltage levels in the power system.

In some urban areas ac underground cable systems have been installed. These are expensive installations that usually cost 2 to 15 times as much as the equivalent overhead circuit. In urban areas with limited land availability and high load densities, underground cable transmission is the only technically feasible way to deliver the required power.

In a few special situations dc transmission has been installed. These are usually circuits that connect the large interconnections or are installed where an electrical "express highway" is needed. Direct current has the advantage that the power flows over circuits may be controlled directly at the terminals. Examples are the Pacific Northwest Intertie and the dc ties between Quebec and the eastern systems in the U.S.

8.2 ASPECTS OF SYSTEM CONTROL

The control of the power generation is coordinated by the utilities to satisfy the demand cycle of the loads. At all times the demand and power generated must be in balance to hold the frequency constant. System operators have to place more capacity online than the expected load demands in order to protect against unanticipated load levels and against sudden shortages that may occur if a plant, unit, or major circuit goes out of service.

8. The control of power generation is coordinated by the utilities to satisfy the demand cycle of the loads.

The generating units in any system are controlled in an optimal economic manner such that the marginal costs of production in the system are as uniform as possible. Centrally dispatched power pools and power broker systems enlarge the economic dispatch area beyond the boundaries of single utility systems. Marginal costs generally increase with demand. Transmission system losses or transmission capacity limitations may bias the generation dispatch such that the marginal costs are not precisely uniform throughout the system, but vary with location.

9. The generating units in any system are dispatched in an optimal economic manner such that the marginal costs of production in the system are as uniform as possible.

The introduction of storage (of water or fuel under a take-or-pay contract) complicates the dispatch problem converting it to one that must be solved to minimize production costs over some time period. Long and short term power exchanges with interconnected systems affect the scheduling of generation as well. Non-utility generation may not be dispatchable by the utility system operators. In small quantities, this generation is considered as a load reduction in scheduling. In larger quantities the operators have to assume that the non-utility capacity has to run.

10. Economy interchange of power reduces the cost differences between interconnected systems.

Economy interchange of power reduces the cost differences between interconnected systems. Economy interchange between systems has grown greatly in recent years since the oil price level changes have upset the historical pattern of fuel prices. Environmental concerns and regulations have fostered economic interchange as generation has been shifted to sources remote from urban load centers. On both coasts, utilities with high concentrations of oil burning generation have increased their importation of energy produced by coal burning plants and hydroelectric plants.

Economy interchanges may be arranged by direct negotiations between system dispatchers or may take place under long term contracts arranged between utilities. In some areas extensive transmission systems have been constructed to take advantage of energy price differences.

The wheeling of power for economy purposes has been the result of negotiations between utilities except for the wheeling under PURPA regulations. Wheeling takes place under a variety of rate structures for transmission service. Simultaneous buy-sell transactions frequently serve the same technical purpose of economy interchange between systems that are not directly interconnected and replace the sale of transmission service.

The automatic generation control systems in use in the U.S. are essential to the successful operation of the interconnected systems. They are designed to control the flow of power over interconnections to their scheduled values as well as controlling the generation for economic dispatch. Since the transmission systems are owned and operated by several hundred different utilities, this control is decentralized into about 150 different control areas. When a control area experiences an imbalance between load and generation, the AGC systems in that area and in the interconnected control areas are able to discriminate between locations. The area with the imbalance is expected to restore the balance between generation and load without long term dependence on the neighboring systems. Intertie flows have to be restored to normal within the time period of emergency capability rating of lines involved.

11. The automatic generation control systems in use in the U.S. are essential to the successful operation of the interconnected systems.

There is no single centralized control of generation in each major interconnection. The coordinated operation of these control areas is essential to the successful performance of large interconnected regions. The industry voluntarily coordinates and polices these operations under the guidance of the NERC Operating Committee. Without these efforts the interties between the utilities would frequently become overloaded and automatically opened, interrupting the flow of scheduled power

12. The coordinated operation of these control areas is essential to the successful performance of large interconnected regions.

13. The industry voluntarily coordinates and polices these operations under the guidance of the NERC Operating Committee.

transactions. These interchanges are also used to share generation reserves in emergencies. If the overall control system were to become disrupted, the effects would be to reduce reliability and increase the requirements for generation reserves in the long run in order to hold service reliability levels at their current levels.

These AGC systems are not perfect, so some level of inadvertent interchange will occur. The current practice in the U.S. is to meter this inadvertent interchange and repay it in kind at similar times. These arrangements are also part of the cooperation between system operators.

14. Operating efficiency is improved by coordinated economic dispatch of separate utilities in power pools and in markets organized under power broker schemes.

Operating efficiency is improved by coordinated economic dispatch of separate utilities in power pools and in markets organized under power broker schemes. Some utilities are members of centrally dispatched power pools where the generation throughout the pool is dispatched on a single system basis. These pooled systems, whether unaffiliated companies or members of a holding company structure, achieve a savings in operating costs and in the planning and implementation of system expansions.

Power broker systems have been established in several regions of the country to achieve operating cost savings without a formal pool structure. These broker systems formalize the market for economy interchange, replacing the one-on-one negotiations between utility dispatchers.

Generation is also controlled to assist in the regulation of system voltages. Control of the generation excitation level will provide a controllable source of VARs. The voltage control devices on the system (e.g., shunt capacitors, SVCs, etc.) all have a limited control range. Supply of VARs by generators is an important tool for system voltage control.

Transmission line flows are normally controlled indirectly by the control of the generation. When a transmission circuit is in danger of being overloaded, the dispatcher shifts generation to reduce the circuit's loading. Many systems utilize a preventative (or defensive) system of generation scheduling to prevent cascading outages and blackouts which could result from the occurrence of a single failure in the system. These security constrained dispatch techniques analyze the generation schedule and transmission system power flows, search for worst case contingency situations, and adjust the generation schedule to prevent the worst case from occurring.

15. Transmission line flows are normally controlled indirectly by the control of generation.

16. Many systems utilize a preventative system of generation scheduling to prevent cascading outages and blackouts.

This results in an economic cost due to increased production costs and also limits the flows over the transmission system by holding some level of transmission capacity in reserve. Although there are no statistics that will prove it, the operating results appear to have been excellent due to the adoption of this practice over the past 20 years.

A consequence of this use of preventative methods of generation scheduling and similar schemes for establishing transfer capacity limits is that available

17. A consequence of this use of preventative generation scheduling and similar methods for establishing transfer capability limits is that available transmission capacity is not fixed.

transmission capacity is not fixed. It varies with load and generation patterns, with circuit and unit availability, and with the different patterns of interchange transactions.

8.3 TRANSMISSION LIMITATION AND TECHNICAL REMEDIES

Transmission systems have been developed to deliver power to load areas, integrate system operations, share generation reserves between interconnected systems, and facilitate the economic interchange of power. Transmission limitations do occur in all systems. In some cases, these are due to the physical limits, current carrying capability or voltage tolerances, while in other cases these limits are the consequence of operational problems. The potential effects of exceeding these limitations depend upon the nature of the limit. Exceeding thermal limitations of lines and equipment may cause damage to these elements. Limitations due to operating procedures affect the production costs when optimal economic dispatch schedules cannot be achieved. Limits affect the ability to share generation reserves, to engage in economic interchange transactions, and to provide wheeling services.

18. Transmission limitations occur in all systems.

19. Limits affect the ability to share generation reserves, to engage in economic interchange transactions, and to provide wheeling services.

Transmission limits, in many cases, are caused by the circuit reactance which impedes power flows and causes line voltage drops. The reactance increases the power angles between generators when power flows increase. Voltage drops must be limited to the range that is controllable by the tap changing transformers and other voltage control devices on the system. Power angles cannot become too large or stability problems will result that may cause generators and power flows to oscillate at low frequencies and ultimately result in system separations.

Transmission limitations related to system operations occur as a result of the power flow distributions which normally take place on the electric power system. When a circuit is suddenly removed the power flows will redistribute instantly and automatically and may result in an overload. If the system cannot be readjusted rapidly enough to restore loadings to normal within prescribed time periods, the alternative is to restrict the flows so that outages do not result in overloaded conditions. Hence the development of security based generation dispatch techniques to prevent these events.

20. Transmission limitations related to system operations occur as a result of the power flow distributions which normally take place on the electric power system.

Loop flows over interconnected system circuits are another consequence of the natural distribution of power flows. These result from interchange transactions between systems. The power will flow where it must to satisfy the physical laws. Simultaneous interchanges taking place on the large interconnected systems compound the problem caused by loop flows and make life more difficult for system operators. In some instances, persistent loop flows may interfere with the operation of systems not participating in the interchanges. Operators may be forced to curtail the interchanges or systems may arrange for the installation of special control devices (e.g., phase shifting transformers) which will reduce the unwanted effects.

21. Loop flows over interconnected systems are another consequence of the natural distribution of power flows.

Voltage control and potential voltage collapse problems may limit transmission flows. These occur when sudden requirements for VARs exceed the available supply. They arise frequently in the systems where large interchanges are scheduled and sudden major circuit outages occur.

22. Voltage control and potential voltage collapse problems may limit transmission flows.

Systems may suffer dynamic problems which require transmission flows to be limited. These may be transient stability problems which cause low frequency oscillations or subsynchronous resonance problems. These problems usually appear in systems with longer transmission distances and have occurred most frequently in the western part of the country.

23. Systems may suffer dynamic problems which require transmission flows to be limited.

Based upon considerations of technical limitations to transmission flows it appears that technical remedies are available to increase transmission flows by substantial incremental amounts. VAR supplies may be installed to aid in voltage and stability problems. Intermediate switching stations may be required to cure a stability limited system with longer lines. Generator stabilizers, series capacitors, and new turbine and boiler controls may be installed on existing plants to increase stability margins and improve power plant response characteristics.

24. Technical remedies are available to increase transmission flows by substantial incremental amounts.

Lines may be rebuilt with new, larger conductors to increase current capacities. Line monitoring schemes which allow the use of current local weather conditions to establish dynamic line capacities may be used. Some circuits may be reconstructed at higher voltage levels. Operating practices may be installed to alleviate stability induced limits.

The development of special protective systems to react rapidly to contingencies may allow the increased loading of some lines which would have been limited under a security constrained dispatch. Generation redispatch may allow the increased use of circuits at some penalty in production costs. Phase angle regulators may be installed in a few key locations to prevent loop flows from using transmission capacity.

The development of emergency plans, operating procedures, and post-emergency restoration schemes may encourage system operators to operate closer to the physical limitations of the system.

All of these technical remedies have been used effectively. There is no universal measure of applicability, cost, or effectiveness of these technical remedies. The limitations which occur are highly system specific and will change with time.

25. There is no universal measure of applicability, cost or effectiveness of these technical remedies.

In the long run, the most effective remedy for transmission limitations is the construction of new transmission facilities. The costs for high voltage overhead construction vary greatly and are very dependent on the cost of securing rights-of-way. Lengthening construction cycles also add to these costs.

26. In the long run, the most effective remedy for transmission limitations is the construction of new transmission facilities.

Line construction costs are presented in the text based on current approximate data. The capacity costs for new transmission construction range from about $1000 per MW-mile at 110 to 138 kV down to about 150 to 200 dollars per MW-mile at 765 kV.

These are for construction only and do not include costs for VAR compensation or losses.

The current announced plans of the industry are such that projected transmission construction levels keep dropping. This is caused by both the decline in new generation construction and the effects of environmental regulations. If the current transmission construction trends persist, the industry may have to live with essentially the current stock of transmission facilities.

27. If the current transmission construction trends persist, the industry may have to live with essentially the current stock of transmission facilities.

8.4 WHEELING AND NON-UTILITY GENERATION

The wheeling of power between electric utilities for economy interchange is a regular practice of the industry. Levels of wheeling have increased as a result of regional differences in fuel costs. As these price levels change the level of wheeling transactions react accordingly.

28. The wheeling of power between utilities for economy interchange is a regular practice of the industry.

Current wheeling arrangements are made between essentially non-competing utilities. These are accomplished technically by having the selling system increase its generation level and the purchaser decrease its level. Changes in transmission system losses are usually supplied by the seller. The interchange schedule is supplied to the area automatic generation control and becomes the responsibility of the selling utility.

29. Current wheeling arrangements are made between essentially non-competing utilities.

Wheeling may occasionally cause technically related transmission problems. The most frequent is that of loop flows. In many cases the effects of loop flows are acceptable and do not cause operating difficulties or restrictions. In other cases where they do, the transaction may have to be curtailed.

The transmission capacity available for wheeling is affected by other transactions taking place simultaneously. Load and generation patterns affect available transmission capacity. Transmission circuit availability, transmission circuit losses, and voltage-VAR problems also influence this capacity at any given time.

30. The transmission capacity available for wheeling is affected by other transactions taking place simultaneously.

Wheeling power is an alternative to generation and the availability of low cost power sources within reach of the system affects both planning and operating practices. Wheeling rates, schedules, and availability vary with the region. Rates are subject to regulation by the FERC.

Non-utility generation is not new in the utility arena. Self-generation and industrial cogenerators have been in existence for most of the industry's history. Since the passage of PURPA in 1978 new qualified facilities, small power producers, and industrial cogenerators have risen in volume and importance. Recently there have been a number of actual and proposed independent power producers.

Non-utility generation sources affect utility system planning and operations. The extent and actuality of proposed non-utility resources causes an uncertainty in utility planning. The longevity of these new sources is of concern to utility planners. The connection of these new resources to the system may

31. Non-utility generation sources affect utility system planning and operations.

affect transmission planning and system development. If the new sources are located near load centers, they may release transmission capacity and improve system performance. If they are remotely located, they may cause the utility to construct new transmission.

The lead time requirements for the new generation are frequently much less than that for new transmission so a coordination problem may arise. Utilities face a high level of uncertainty concerning the many of the announced, planned developments of non-utility generation do not actually occur.

32. Utilities face a high level of uncertainty concerning transmission system requirements since many of the announced, planned developments of non-utility generation do not actually occur.

System operations and economy may be adversely affected by non-utility generation in large quantities. Many utilities have installed larger steam units which were not designed for cyclic operation. If the non-utility generation is non-dispatchable and is large enough to supply a major portion of the demand at light load periods, the utility may have to devise uneconomic generation schedules to accommodate this non-utility generation. In some cases, projected levels of uncontrollable generation have been such that economic interchange transactions have had to be curtailed.

33. System operations and economy may be adversely affected by non-utility generation in large quantities.

Non-utility generation affects the level of spinning reserve required and may seriously affect the network loading and security dispatch patterns. Non-utility generation requires coordination with utility emergency operating procedures. Non-utility generation is frequently shutdown automatically during system generation shortages by underfrequency relays, further adding to the generation shortage.

Distributed generation sources are smaller units connected to the distribution system. They cause a different set of technical problems than the larger units. Some are induction generators that may become self-excited at the wrong time. Some generate harmonics on the power distribution system. All of these technical problems are curable with the cooperative efforts of the utility and non-utility generators.

It appears that in many systems, wheeling of non-utility generation can be accommodated in smaller amounts. When the requirements for wheeling become large it may cause problems with the area control if the non-utility generation is non-controllable. Large amounts of wheeling of this type of generation will increase the requirements for metering, communications links to the control center, and may increase levels of inadvertent interchange.

The same general observation may be made with regard to retail wheeling for utilities or for non-utility generation. In smaller amounts, the current system controls can accommodate increased levels of retail wheeling. In larger amounts and with a large increase in the number of retail wheeling transactions, the current schemes for automatic generation control may become taxed beyond their capabilities. A large increase in the number of transactions would require a corresponding increase

34. In larger amounts and with a large increase in the number of retail wheeling transactions, the current schemes for automatic generation control may become taxed beyond their capabilities.

in metering, monitoring, and control points for AGC systems. Arrangements for standby service and contract terms for inadvertent interchange payments may be required, changing the nature of the current systems and arrangements.

Retail wheeling in unlimited amounts has the potential for causing serious system control problems. In combination with a large increase in uncontrollable non-utility generation, this could seriously degrade the performance and reliability of the electric power systems.

35. Retail wheeling in unlimited amounts has the potential for causing serious system control problems. In combination with a large increase in uncontrollable non-utility generation, this could seriously degrade the performance and reliability of the electric power systems.

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